Minister of State for Cariboo
Province of British Columbia

Cariboo Woodwaste Study

March 1989

SANDWELL SWAN WOOSTER INC.

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REPORT X7801/1
CARIBOO WOODWASTE STUDY

MINISTER OF STATE
CARIBOO DEVELOPMENT REGION
VICTORIA BRITISH COLUMBIA

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SUMMARY

The Minister of State for the Cariboo Development Region engaged Sandwell Swan Wooster Inc. to conduct a study to determine the feasibility of using woodwaste as a fuel for thermal electric power generation and co-generation applications. The incentive for such a study arises from the Region's desire to resolve increasing concerns about air pollution and to find an economic use for slightly more than 1 million tonnes (about one million bone-dry units - BDUs) per year of sawmill woodwaste. This quantity is now disposed of in inefficient burners that reduce the air quality in many communities. In addition, some 35 thousand tonnes are dumped annually as land fill, requiring land, maintenance, and monitoring.

The Cariboo Development Region covers an extensive area of north-central British Columbia. The major manufacturing industry within the Region is forestry which supports some 44 sawmills and related plants. Within the Region this industry creates annually approximately 1.9 million tonnes (1.8 million BDUs) of mill residue in the form of woodwaste. At present only 43 percent of this waste is commercially used, primarily in forest industry ancilliary steam and power plants. After completing a regional inventory of waste availability, the study focussed upon Williams Lake as one of the most opportune communities for private investor development and early corrective action.

Within Williams Lake the City's six sawmills currently generate over 300,000 bone-dry (BDT) tonnes annually of woodwaste. This represents one of the most concentrated sources of woodwaste and resulting air pollution in the Region.

The volume of woodwaste available in Williams Lake is sufficient to fuel a 60 mega-watt (MW) thermal plant. Additional fuel can be economically trucked from 100 Mile House, or Quesnel where a back-haul of wood chips is possible. Other potential woodwaste sources, collection centres and associated thermal plants in the Region could be located at Prince George, Mackenzie and possibly McBride.

Until recently, the sale of independently produced electric power was not practical owing to the monopoly enjoyed by B.C. Hydro. However, in late 1988, B.C. Hydro released a new policy that encourages private development of electric power and provides for purchasing it from independent power producers (IPPs). In December 1988, B.C. Hydro issued a public tender call for proposals for the independent supply of a total of 180 to 200 MW of power for its integrated system. Initial proposals are due 31 March 1989. The plant described in this report is intended to be an IPP.

In its call for proposals, B.C. Hydro has indicated that it would consider purchasing power at a price up to its long term marginal cost of 3.8 cents per kilo-Watt hour (cents/kWh). However, the final price is subject to negotiation based on a number of defined and undefined factors. Special arrangements may apply for socially beneficial projects incorporating environmental and co-generation benefits.

In addition to power sales, there is potential in Williams Lake for the sale of 3 to 8 percent of the thermal plant's energy as heat or steam to adjacent sawmills. A further potential opportunity may exist for sale of about 20 percent of the plant's steam capacity and about 25 percent of the electric power to a proposed wood product board plant. Though this report depicts an independent dedicated thermal plant of 60 MW, a combined venture of co-generation could improve both the economics and size of the electric generating facility. Additionally, the prospects for sale of low temperature heat (hot water) to other possible users such as tree nurseries and greenhouses is good. Unlike high temperature heat this low grade heat can be sold without an equivalent offset of electric energy.

A convenient, 8 to 10 hectare site for the thermal plant exists in the B.C. Rail industrial area at the north end of Williams Lake. Adjacent to three sawmills, the site offers economical delivery of woodwaste by truck and conveyor. The proposed site is adjacent to sufficient potential industrial land. This land could accommodate future processing plants and a large nursery which could use process heat or power from the thermal plant. As environmental impact analysis have not been carried out during the site selection process, it must be emphasized that the final site selection should be made after a detailed assessment of the potential impacts of the project on the receiving environment.

The plant design reflects several features which minimize the environmental impact. Its electrostatic precipitator will reduce particulate emission levels and ensure compliance with the latest guidelines of the Ministry of Environment. Water requirements can be met, with minor modifications, to the City's water system whereas plant effluent can be processed within the City's existing treatment plant. The ash handling system produces about 5,000 tonnes per year of ash for disposal and incorporates char separation and reinjection. The ash is non hazardous and can be disposed of in most landfill locations including the existing City disposal area. More detailed assessment of alternate pollution control systems should be carried out at the design phase.

Several furnace designs have been reviewed; these comprise conventional boiler furnaces with sloping or moving grates, and fluidized bed furnaces. The capital cost premium for a fluidized bed furnace would be about $10 million and would not offer sufficient additional technical or commercial benefit in a base-loaded woodwaste fired thermal plant.

Alternative conversion processes have been reviewed. Technologies exist for the conversion of wood waste into building materials, pulp, chemicals and secondary-fuels. The installation of such systems requires the participation of entrepreneurial groups willing to accept the technological, marketing and financial risks. The installation of such systems would have to address the disposal and environmental problem in a cost effective and timely manner. It is for this reason that the study concludes that a conventional steam generating thermal plant, producing saleable heat and power, is the most likely solution. In particular, the boiler and turbine generator combination offers established performance and secure long term sales contracts for its product.

In order to evaluate the economic viability of the concept of establishing a woodwaste-fuelled thermal electric generating plant in Williams Lake, two financial models were developed. One model is described as the Option A, which consists of a stand-alone plant obtaining prepared and delivered woodwaste from local sawmills. The other model, Base Case, consists of the same plant but involves an additional capital investment at the plant and for associated conveyor facilities between some of the sawmills and the plant.

Raw woodwaste transported to the plant by truck or conveyor would be centrally hogged as fuel suitable for burning.

The Base Case capital cost of the proposed 60 MW thermal generating plant has been estimated to be $119.2 million for a plant complete with conveyors and trucking from local sawmills. A stand-alone plant, Option A, designed to receive prepared woodwaste is estimated to cost $113.2 million. The cost estimate includes equipment and structures, working capital and pre-operating expenses; not included is capitalized interest on loans incurred during the construction period. The cost of additional emission control equipment necessary to meet the proposed Pollution Control Objective represents about one-half of one percent of the total project cost. Costs in addition to this would be incurred if a bag house system is selected instead of an electrostatic precipator. A construction period of about 2 years would be needed following the required permit and approval phase.

Once in operation the plant would directly employ an estimated 34 persons, creating an annual payroll of about $2 million. Consistent with similar projects of this type, some 60 other jobs could be expected to be created in support and related businesses.

The financial performance of the plant has been analysed under a variety of assumptions. Given B.C. Hydro's present power purchase policy, a 20 to 30 year power supply contract is possible. The sawmills in Williams Lake have indicated that they would also enter into a 20 year fuel supply contract under certain conditions. The ability to establish such contracts would help to secure project financing on reasonable terms.

The concept for development of the thermal plant assumes that it would be a private sector enterprise. Normal commercial lending terms, investor expectations and risks have been considered in the financial evaluation of the project.

The study has assumed that a debt/equity ratio of 2:1 would be appropriate. Under current conditions the annual rate of return expected by equity investors in such a venture is expected to be 10 percent in real terms (non inflationary). Lending rates are estimated to be at 5 percent in real terms.

The financial analysis in the study has determined that the return on equity (ROE), with power priced at B.C. Hydro's long term marginal cost of power, is only 3 percent. This is far short of the return required by private investors. To realize the desired 10 percent real return on equity the power price would have to be in the order of 5.6 to 6.0 cents/kWh rather than the 3.8 cents/kWh indicated by B.C. Hydro. Nevertheless, the unit power costs do compare favorably with B.C. Hydro's large hydro projects when similar interest, ROE, taxes and interest during the construction criteria are used.

The project does offer a number of benefits in a socio-economic sense: clean disposal of woodwaste; reduction of air pollution in Williams Lake; generation of power for sale to B.C. Hydro; generation of heat for sale to other potential industries that might locate in Williams Lake; creation of additional employment in the City; and a strong desire of the community to see the project proceed. With these benefits, the study has sought to identify elements of innovative development packages that might combine to realize the project.

Numerous sensitivity tests have been made to identify the key variables that affect the project's financial success. These tests include different power rates, disposal fees, increased debt/equity ratios, lower lending rates, capital assistance grants, and increased

heat sales and prices. A number of sensitivity analysis cases have been summarized in the report. One example shows that the required investor return could be obtained if a "disposal fee" of $15 - $19 per Bone Dry Unit were charged, however, this rate is well above current avoided costs of alternative disposal for the sawmills. It should be noted that future avoided costs are expected to increase if more stringent environmental guidelines are put in place. Similarly, a more highly levered capital structure with a debt equity rate of 4:1 would reduce power prices to about 4.9 to 5.2 cents/kWh. Each of these examples brings the unit power price within the range of B.C. Hydro's unit power costs if similar financial comparisons are used.

In order to realize the advantages of such a proposed plant whether it be a stand alone thermal electric plant or an integrated co-generation facility, a definite development strategy needs to be considered.

The study recommends that a dedicated development group be considered for the sole and limited purpose of sponsoring this project within the mix of public and private sector interests.

Sandwell Swan Wooster Inc. was assisted in this study by Don Baack & Associates, Price Waterhouse Management Consultants and Washington Water Power.

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INTRODUCTION

The Cariboo Development Region is evaluating the opportunity for using woodwaste as a fuel for thermal electric power generation and co-generation applications. Substantial amounts of woodwaste are produced in several major centres within the Region. Appropriate disposal of the waste is a Regional concern. As Williams Lake is one of the largest concentrated sources of woodwaste in the Region, the City was selected as the site to specifically evaluate for a woodwaste fueled thermal plant. Williams Lake was selected also because of the significant air pollution presently created by conventional burning of the wastewood at the adjacent mills.

The Cariboo Development Region retained Sandwell Swan Wooster Inc. in October 1988 to complete a study of Regional woodwaste supplies as well as evaluating the feasibility of a woodwaste thermal plant at Williams Lake. This report presents the results of work completed under this assignment, the summary of work completed and the consultants recommendations.

Sandwell Swan Wooster Inc. was assisted in this study by Don Baack & Associates, Price Waterhouse Management Consultants and Washington Water Power.

THERMAL PLANT TECHNOLOGY

General

The emphasis of this study is to investigate the feasibility of the construction of a thermal power plant to utilize wood wastes in the Williams Lake Area. This section reviews thermal plant technology only; other possible conversion methods are reviewed under "Alternative Processes".

Prior Studies

Thermal generation in this geographical area has been examined in detail in two reports. These are:

a. British Columbia Energy Commission, CO-GENERATION OF STEAM AND POWER STUDY, QUESNEL, B.C. in December 1977 by H. A. Simons.

b. B.C. Hydro and Power Authority, QUESNEL THERMAL GENERATING STATION ENGINEERING AND ECONOMIC STUDY in September 1979 by Sandwell and Company Ltd.

These studies established contemporary economics and technology. The "cogeneration" aspect of the studies refers to a small proportion of the steam being used for district or dry kiln heating. The economics of power production were shown to be marginal, with profitability being heavily dependent on B.C. Hydro rate structures. The conclusion of the Sandwell Report was that "the analysis indicates that the assumed price level for the

delivery of electrical energy to the B.C. Hydro grid has a more serious impact on the rates of return than any other variables such as capital cost or operating cost".

Four cases were considered by the Sandwell Report; for the case most similar to the present specification, a price of $0.020 per kWh (in 1979 $) would have produced an internal rate of return of only 2.2 percent.

Existing Plants

A site visit was made to the Kettle Falls plant owned by Washington Water Power Company to review the technology and operating experience gained since the plant started up in 1983.

Other plant information and studies have been reviewed for technical and economic information. Similar plants exist at Chapleau, Ontario; Burlington, Vermont; and Shasta, California.

Kettle Falls Generating Station, Washington

The Kettle Falls Project is a 46 MW woodwaste-fueled generating station located at Kettle Falls, Washington. The plant is wholly owned and operated by The Washington Water Power Company of Spokane, Washington. The project was proposed in the late 1970s, when energy was perceived to be in critical supply, to provide an increment of generating capacity. In addition, such a project would add stability to the extreme north portion of the Company's distribution system.

Construction began in June 1981 and the plant went into commercial operation in December 1983. The unit is located on 46 acres with all fuel being delivered by truck. The plant has a single boiler with a travelling grate (supplied by Combustion Engineering) and is rated at 415,000 lb/h at 970°F and 1450 psig operating conditions. The plant generates into the local transmission system at 115 kV.

The capital cost of the facility was U.S.$93 million including financing costs. The plant is one of several generating stations that supply the utility's customers. The recovery of costs of the facility is through the standard utility rate-based provisions of the state regulatory bodies.

The service factor of the plant was planned to be 75 percent but the actual availability of the plant and a higher than expected market for power has supported a service factor between 85 percent and 90 percent over the last two years. The plant is currently available for power generation in excess of 91 percent of the time.

Operation of the plant is dependent upon an economic balance between the price of delivered fuel and the value of power on the secondary market. To date, fuel costs and demand have supported greater than expected use.

All fuel is delivered by semi-trailer and tandem unit trucks. About 85 to 100 loads are received each day, five days a week. The plant consumes about 68 T/h. Fuel supply has been more than adequate with the stockpile often adequate for 45 to 60 days operation.

Fuel is supplied from approximately 15 sawmills in a 135 km radius from the plant and consists of sawdust, shavings, bark and other sawmill waste. Most fuel is sampled for

moisture on arrival and payment is made on a bone dry unit (BDU) basis. The average cost of the delivered fuel is $5.70 per wet tonne.

The plant includes a staff total of 30 people with a total labor cost of about US$ 1.2 million per year.

Burlington Vermont - McNeil Plant

The Burlington Project is a 50 MW facility located in Burlington, Vermont and was completed in 1984. The plant consists of a single Zurn boiler rated at 480,000 lb/h, and a single turbine generator (Brown Boveri) rated at 50 MW. The plant is owned and operated by the City of Burlington Electric Department. The total cost of the plant was US$ 65 million, not including interest during construction. The capital costs of the project form part of the rate base with other generation facilities which include 28 MW of gas-fired turbine capacity and 30 MW of other thermal generation. The boiler burns chipped whole logs on a travelling grate.

The project was conceived in 1976 when generation planning studies found that 50 MW of additional capacity would be needed by the early 1980s. The various fuels that were considered included; nuclear (inappropriately sized for the generation needed), natural gas or fuel oil (prohibited by the Fuels Use Act in force at that time), coal (expensive fuel plus the need for high cost scrubbers), and wood which was available (80% of Vermont is wooded). Construction began in September 1981. The project required approximately 600,000 manhours of labor to construct.

All fuel is now delivered by rail. The cars are bottom-dumped from an elevated trestle 240 feet long and 35 feet above the ground. The project has experienced many problems with fuel handling, including, problems with unloading frozen fuel from rail cars, noise and dust complaints from the neighbors, and increased labor costs. Truck hauling was discontinued after the project went into operation as complaints regarding the truck traffic forced all fuel to be transported by rail. Current fuel costs are approximately US$ 22 per wet tonne. All fuel is derived from whole log chipping operations at various regional locations.

The current staffing is 49 people, 41 in the plant and 8 in support roles such as engineering, forestry and management. The total direct labor cost for the plant operation is about U.S.$1,200,000 not including support staff or overtime.

Since starting commercial operation in 1984, the unit capacity factor for the plant has ranged from 20 percent to 40 percent due to the relatively high cost of operation. Less expensive energy is available which often displaces the plant. The availability has been good (over 85 percent) in part because the service factor is so low. This standby time allows some maintenance to be completed which would otherwise require a scheduled outage. Forced outages are less than 1 percent.

The Chapleau Co-generation Project, Ontario

The Chapleau Co-generation Project is a 7 MW waste wood-fired electric generating station located in Chapleau, Ontario. Chapleau is a major lumber producing area in northern Ontario with three mills located in the community of 3,400.

This project, which began commercial operation in February 1987, was developed in close cooperation between government, private industry and Ontario Hydro to solve an

environmental air quality problem resulting from the burning of waste wood material in teepee burners.

In April 1984, the Ontario Ministry of Energy commissioned a study to evaluate solutions to the air quality problems. The study led to a call for proposals by the Ministry for private developers to build a facility to dispose of the waste wood material in an environmentally acceptable manner. Financial assistance was provided by the Ministry of Energy and the Federal Department of Energy, Mines and Resources through the "FIRE" program (Forestry Industry Renewable Energy).

A limited partnership, Chapleau Co-generation, Ltd. was selected to develop and own the project. The major owner of Chapleau Co-generation, Ltd. is Foster Wheeler, Ltd. of St. Catharines, Ontario. The three mills together own 25% of the project. This pilot project was commissioned to demonstrate the commercial feasibility of wood-fired cogeneration. A second goal was environmental improvement and resource conservation.

The project cost $15 million.

The Chapleau plant consumes 100,000 T/a of wet woodwaste from the three lumber mills. The waste material is delivered by conveyor belt from one of the mills and by truck from the remaining two mills. The waste material is free to the project at the mills. The plant is responsible for the transportation which averages $24.37 per wet tonne.

The total on-site staff consists of 14 people. Additional manpower is required for extraordinary maintenance, snow removal and the annual shutdown.

The energy produced is sold to Ontario Hydro at a 1988 rate of 4.494¢/kWh. The unit is dispatched to run as much as possible with an availability over 90 percent. The project developer has confirmed that the project is not performing up to financial expectations due to the low rate paid by Ontario Hydro.

The Chapleau project demonstrates the feasibility of eliminating a waste disposal problem in an environmentally acceptable manner. The low energy buy-back rates from Ontario Hydro have affected the financial viability of the project.

The Wheelabrator Shasta County Project

The Wheelabrator Shasta Energy Company operates a 49 MW (net) plant in Shasta County, Northern California.

The plant burns 750,000 tons of millwaste and forest residues and produces 375 million kWh of electricity per year under long term contract to the Pacific Gas and Electric Company.

The plant design includes three independent wood-burning units, comprised of three wood-fired travelling grate furnaces with utility-type high pressure boilers. The highly automated woodyard design includes capabilities to accept mill wastes, chips, and unmerchantable whole logs (culls) up to 6 feet in diameter, which are chipped on-site for fuel. The plant design also includes three electrostatic precipitator units, three condensing turbines, and two multicell wet cooling towers.

The facility incorporates staged overfire air combustion in specially shaped furnaces and a zero water discharge system by use of staged cooling towers.

The project construction was commenced in June 1986 and completed to operational status in December 1987. Capital costs were approximately $107 million U.S. There are 40 full time operating staff.

Best Available Technology

Choices are available for the selection of the unit processes which constitute a thermal power plant. Review of the available technology indicates the following major process alternatives.

1. Combustion Systems

The fuel may be transformed into heat on a conventional travelling or vibrating grate and furnace, or in a fluidized bed furnace.

The conventional moving or sloped grate systems offer advantages of lower cost and established design. In these systems the heavier fuel particles are burned on the grate and the lighter particles are burned in suspension. A fluidized bed system burns all of the fuel in suspension; the fuel bed is kept in constant motion by the underfed combustion air.

In comparison to a grate, a fluidized bed system is less sensitive to fluctuations of fuel size, moisture content and composition, and is appropriate for "difficult" fuels such as municipal solid wastes, peat, wet bark, etc. The bed may be loaded with limestone to absorb sulphur in such fuels as coal to reduce acid forming emissions. Control of nitrogen oxide emissions can also be influenced by low temperature combustion methods. Finally, the output of a fluidized bed system can be substantially and rapidly rto match variations in process demand. A fluidized bed system would increase the capital cost of the plant by $7 to $10 million. The superior technical attributes of the system can, in this case, be matched by conventional design as follows:

Fuel quality:	Uniform and dry. Conventional system can be adjusted for optimum combustion.
Emissions:	Guideline levels can be achieved by conventional system.
Turndown:	Plant is base-loaded, large and/or rapid turn-down is not required.

Conventional moving or sloped grate systems were therefore selected as appropriate technology for the Power Plant.

2. Particulate Emissions Control

The flue gases leaving the boiler carry with them ash and char particles which must be captured before they enter the stack. The new environmental guidelines, presented in Appendix 11, are likely to be mandatory in the next few years. The selected technology is intended to fulfill the requirements without the need for future retrofit engineering.

The larger particulates are removed by mechanical cyclone or "multiclone" collectors at the boiler exit. The smaller particles must then be removed by electrostatic precipitators (ESPs) or by filtration methods. In the latter case the gases are forced through bag-filter banks, and the dust discharged to hoppers. With electostatic precipitators the particulate aquires a negative electrostatic charge which causes it to stick to collector plates with the reverse polarity. The dust is subsequently removed by inertial forces, or "rapping", and falls into hoppers.

The collection efficiencies of baghouses and ESPs are identical over a wide range of particle sizes. The high maintenance costs of baghouses, the temperature limitations of the filter material, and the higher fan power required, result in the selection of ESPs in many situations despite their higher capital cost. However as particle size is reduced below the 2 to 3 micron (0.000002 m) range, the efficiency of a bag filter system remains relatively high. Some recent environmental concerns exist regarding toxic hydrocarbon particulate emissions within this size range. Revaluation of the problem at the design stage could dictate the use of bag filters.

For the purposes of this study, an electrostatic precipitator has been selected as representing the upper limit of capital cost. The particulate emission level is equivalent to a ten-fold improvement over the previous British Columbia guidelines. This additional performance represents an extra capital cost of approximately $1.1 million.

The reinjection of fly ash into the boiler is practiced at several installations, including Kettle Falls, to reduce carbon loss and reduce ash volumes. This has implications regarding concentrations of particulate within the boiler furnace and with regard to particulate size distribution. These factors can affect the ultimate design of the precipitator; the capital cost estimate is conservative and should accommodate appropriate design variations.

General Assessment

Wood-fired power plant technology is well established in the utility and pulp industries. In the latter, hog fuel is used for the co-generation of power and process steam and the design experience within the Province of B.C. is considerable. In particular the boiler designs for this application will be derived from pulp industry precedents.

A wood-fired power plant therefore offers a solution to the waste disposal problem which is largely free of technical risk, has wide precedence in North America and Europe, and can conform to the strictest current environmental protection legislation and limits.

Power Plant Description

The 60 MW plant recommended for operation at Williams Lake is described in detail in Appendix 8, "Power Plant Details". The plant and ancillary equipment consist of the following:

1. A fuel handling system capable of receiving all the future supply of fuel by truck and by direct conveying from adjacent mills. Provision is made to "hog" the fuel on site prior to delivery to the fuel storage area. The fuel is then reclaimed and fed to the boiler.

2. A wood-fired boiler of conventional bi-drum design equipped with moving grates. Modifications to furnace design or firing methods may be required at a design stage to provide optimal combustion.

3. A condensing turbine generator set providing for 3 stages of feedwater heating and extraction of steam for process use.

4. Flue gas clean-up train comprised of a mechanical collector and a twin-chamber electrostatic precipitator.

5. A condenser cooling water circuit comprising pumps, piping, condenser and cooling towers.

6. Associated plant including make-up water treatment, boiler feedwater treatment, cooling water blowdown, and a laboratory providing monitoring and analysis of the critical streams, particularly those with potential environmental impact such as stack particulate and opacity, boiler blowdown, cooling water discharge and ash.

Alternative Plant Sizes

The plant capacity is accomplished in this study by a single boiler and turbine generator. Co-incidentally, the boiler capacity is close to a conventional design size. Consequently, if a larger plant capacity is required by an increase in available fuel, the design is likely to incorporate more units rather than larger units.

WOODWASTE SUPPLY

General

The projected supply of woodwaste in the Cariboo Development Region has been based upon detailed modelling of mills in Williams Lake. This data base has been expanded throughout the region based upon project questionnaires to all mills listed in the region. This data was supplemented by reports and statistics from the B.C. Forest Service.

Emphasis on volumes, composition and moisture content projection are especially important for the Williams Lake mills. Sandwell focussed attention on this locale to ensure that thermal plant sizing and design reflected the woodwaste supply characteristics.

Cariboo Development Region

A supply 3.5 times that of the Williams Lake supply is currently available from the area outside Williams Lake for approximately the cost of transporting it to the site. The details of available supply are shown in Appendix 6.

In summary, the additional available supply of woodwaste by electoral region is shown in Table 1:

Table 1 - Regional Woodwaste by Electoral Region MBDU

	000 BDU/a
Williams Lake Area	293.9
Cariboo excluding Williams Lake	405.0
Prince George North	139.6
Prince George South	493.3
Total for Region:	1331.8
Total beyond Williams Lake	1037.9
Percent of Williams Lake Volume	22

It should be noted that many producers expect to be able to sell sawdust and possibly shavings to a pulp or other woodfibre using facility within five or ten years. In time, with probable reductions in logging to more closely approach the sustainable Annual Allowable Cut, there will be pressure for increased sorting of wood fibre as its value increases. Demand will increase gradually. Although 40% to 50% of woodwaste is white wood probably half of the amount will be practical to remove for pulping or reconstituted panels. In the long term the supply of wood waste could decline by perhaps 25 percent from present levels.

Williams Lake

The fuel supply for a Williams Lake cogeneration facility has been determined with the cooperation of the mills in the Williams Lake area. The annual fuel supply expected to be available after 1993 is based upon the current woodwaste generation, the expectations of the individual Williams Lake mills and District Ministry of Forests staff. The future supply is estimated to be 90 percent of the currently available annual volume.

Table 2 - Future Annual Williams Lake Woodwaste Production

Item	Units	Quantity (000)
Annual Fuel Available	BDU	294
	BDT	353
	BDt	320
Average Moisture Content	% Wt. Wet Basis	38.4
Average Heating Value (dry)	MJ/kg	22.1
	Btu/lb	9512

The predicted reductions in fuel supply reflect the individual mills' expectations about the future including the future supply of timber resources and the internal steam generation needs of the individual firms.

The current fuel supply is expected to be 327,000 BDU per year made up of the following components:

Table 3 - Current Annual Williams Lake Woodwaste Production

Fuel Source	BDU Volume (000)	Percent
Log Yard Debris & Lily Pads	19	5.7
Cedar Chips	10	3.0
Sawdust & Chip Fines	103	31.6
Shavings	48	14.7
Bark	181	55.2
Mill Usage	-34	-10.2
Total Net Residue	327	100.0

A number of factors such as logging equipment, annual allowable cut, lumber markets, weather and labour relations affect the woodwaste supply produced by the Williams Lake sawmills. The equipment and methods in which the timber is harvested has a significant impact on the bark and lily pad quantities delivered to the mill.

Currently, field operations are moving toward the use of feller bunchers and automated delimbing and bucking for a large portion of the lodgepole pine harvest. The use of this technology means that a larger quantity of bark, estimated at 30%, will be scraped off and left in the woods rather than brought to the mill site. In addition, lily pads are in some cases removed in the woods resulting in the reduction of the available fuel at the sawmill. Impact of all of these factors has been taken into account.

Mill operations woodwaste is dependent upon the saw sizes and kerfs used in the facilities. Little change in saw size is expected in the next 10 years.

Shavings volume in planer operations is a function of the sawing accuracy, and will decline with more accurate sawing. Shavings represent 12.5 percent of the supply and could be reduced if significant capital is expended to improve each mill's sawing accuracy. Such changes are not contained in current mill plans.

Cedar chips represent 3.2 percent of the fuel supply, and it is possible they could be used in a pulping operation at some point when other pulp mill fibre supplies become scarce and more expensive.

The log yard debris and lily pads represent 7.9 percent of the residue supply, and are not expected to change significantly over the next 5 to 10 years. A trend to bucking of small logs in the field would reduce log yard breakage. One mill operator is presently doing this and the effect has been included in the forecast.

There is a large resource of timber in the Williams Lake area. The key question in removing the timber is whether it can be economically harvested and reforested. The factors affecting this decision are the log harvesting, the log and lumber transportation and the lumber conversion cost and the selling price of the lumber products.

The estimates of future operating levels of the mills were made by the operators and Sandwell. No one expects the harvest level to increase, and two operators expect the harvest to decline after five years. One predicts a 25 percent decline, and the other suggests a 1 in 4 chance that the harvest will decline by 25 percent.

The reason these operators expect a decline in harvest is that the current harvest level of 4,104 thousand m^3 per year is up considerably from the levels of 1979 and 1982 as shown in Table 4:

Table 4 - Annual Timber Harvest - Williams Lake Timber Supply Area

Year	Quantity (000 m^3)	
1979 (Actual	2,736	Source: Mr. M. Carlson, RFP, Regional Manager Cariboo Forest
1982 (Actual)	2,942	Source: Mr. M. Carlson, RFP, Regional Manager Cariboo Forest
1987 (Actual)	4,104	Source: Mr. M. Carlson, RFP, Regional Manager Cariboo Forest
1989 (Projected)	3,992	Source: Don Baack & Associates

The rapid increase in the harvest from 1982 to 1987 is the result of the infestation of the mature and near mature timber stands with the mountain pine bark beetle. The 1981 Annual Allowable Cut (AAC) was 2,500 Mm^3. In 1985 the AAC was increased by 50 percent to remove timber damaged by the mountain pine bark beetle. The increase is scheduled to end in 1990.

Subsequent studies of the timber resource using updated timber stand yield tables and the forest inventory adjusted for the damage done by the mountain pine bark beetle show that an AAC of 3,125 Mm^3 to 3,445 Mm^3 can be sustained for the decade 1990-2000 and a long term harvest level of 2,865 to 3,415 Mm^3 per year can be sustained.
If the previously uneconomic timber in the blocks located on the western end of the Williams Lake Timber Sale Area is included in the timber supply base, the long term even flow AAC of 3,889 Mm^3 can be achieved.[1]

[1] Williams Lake TSA Timber Supply Analysis Report. B.C. Ministry of Forests, Inventory Branch, Sept. 13, 1988.

Existing use of woodwaste has been identified and counted. Two mills, Lignum and Weldwood, are using residue to fire boilers. The Lignum operation uses sawdust and shavings to fire a hot-oil space heating system which heats the plant during cold months. An estimated 33,000 BDU are used in this application. Weldwood uses sawdust and planer shavings to fire a boiler for lumber drying. Weldwood reserved woodwaste for their own use.

Fuel Valuation

Many different means could be used to value the fuel. Since the fuel has no market value at present, one approach would be to value the fuel on the basis of avoided cost as shown from the consultants' survey results.

Table 5 - Estimated Avoided Annual Costs - Wastewood Disposal

Facility	Value Per Year ($000)
Lignum	110
Jacobson Brothers	50
Weldwood	NIL
Pinette & Therrien	NIL
West Fraser	50
Jackpine	20

Weldwood and Pinette and Therrien suggest that the avoided cost of disposing of the fuel is nil. However, Don Baack & Associates estimates that the avoided cost will most likely range from $40,000 to $60,000 per year minimum. This cost would cover burner and conveying equipment wear-and-tear and maintenance on the disposal system but not the amortized costs of new burners.

While the residue is not currently marketable, several mill operators expect the wood fibre residue to become more valuable in the future as pulp or other wood fibre demand comes on line within a reasonable haul distance of their plant. The six mill managers generally agree to a long term (20 year) arrangement for bark wastes but also wish a right of first refusal for possible higher value whitewood. It is clear that the value and term of the fuel supply contracts must be negotiated.

All participating mills will need to install equipment to size the residue for transport to the cogeneration site if a centralized hogging concept is not chosen. It is possible that a centralized hogger facility could be constructed but costs of this facility will have to be considered in the negotiation between the mills and the cogeneration facility operator.

Jacobson Brothers and Lignum, the mills located on the southwest of the City of Williams Lake, would be expected to participate in the fueling of the power plant. They do not wish to be penalized by incurring extra costs for trucking waste due to their greater distance from the plant. To offset this situation the fuel could be purchased FOB

producing mill or the hauling cost of fuel transportation equally distributed among all fuel producers.

Opportunities for Cogeneration Facilities

Jacobson Brothers and Lignum are necessarily excluded from consideration as customers for co-generated drying kiln heat, as the distance from the proposed thermal plant site makes their use of the cogenerated heat impractical. Three of the four remaining mills do present opportunities for the use of heat from the proposed power plant.

Weldwood is currently in the process of deciding whether to increase boiler size to produce more process steam. This may be an opportunity for a cogeneration facility if it can be made compatible with the needs of the sawmill, and be brought on line quickly.

At this time, West Fraser uses gas kilns and gas to heat the sawmill. Pinette and Therrien has gas kilns as well; however, there may be an opportunity for cogeneration use in both cases if the replacement or remodeling of lumber drying facilities can be made economically feasible.

Table 6 - Summary of Williams Lake Woodwaste Production by Sawmill

		Lignum	Jacob Brs	Weldwood*	Pinette & Therien	W Fraser	Jackpine**	All Mills (000 BDU)
CURRENT OPERATIONS								
Total Logs	Mm^3	798,548	809,000	800,000	800,000	713,000	71,847	3,992.2
Total Debris/Lily Pads	BDU	9,041	2,634	0	3,809	2,627	527	18.6
Total Chips/Cedar Residue	BDU					9,792		9.8
Total Sawdust	BDU	31,998	22,044	0	24,461	22,732	2,110	103.4
Total Shavings	BDU	10,847	9,986	0	12,399	14,509	294	48.0
Total Bark	BDU	39,027	35,617	35,131	37,094	30,880	2,964	180.7
Total Residue	BDU	90,913	70,280	35,131	77,762	80,540	5,895	360.5
Deduction: Plant Use	BDU	33,333						33.3
Available Residue	BDU	57,580	70,280	35,131	77,762	80,540	5,895	327.2
PROJECTED OPERATIONS								
Reduction factor	%	100.00%	81.25%	100.00%	100.00%	75.00%	100.00%	90%
Total Fuel Available	BDU	57,580	57,103	35,131	77,762	60,405	5,895	294.0

Average moisture content 38.4 percent

** Operation of Jackpine, or similar smaller sawmill, assumed over long-term projection.
* Weldwood items listed as "0" are those used for lumber drying purposes.

(X7801-1)

SANDWELL SWAN WOOSTER

Present Disposal Methods

At present approximately 40 percent of the woodwaste produced in the Cariboo Development Region is used in steam or power generation at various forest product plants. An additional 3 percent is sold for a variety of commercial applications such as mulch for nursery use.

Table 7 presents the summary results. For more details refer to Tables 6-1 and 6-2 in Appendix 6.

Table 7 - Summary Woodwaste Supply and Disposal - Cariboo

Woodwaste Use	Quantity (000 BDU)	Percent of Total
Steam Power Heat	722	40
Fibre Use	0	0
Local Sales	50	3
Total Commercial	772	43
Disposal Landfill	32	2
Disposal Incinerated	1,007	55
Total Surplus Available	1,039	57
Total Woodwaste Production	1,811	100

As discussed elsewhere in this section, a portion (approximately 10 percent) of the woodwaste produced in Williams Lake is used for steam or heating purposes.

A total of 55 percent of the woodwaste in the region is disposed of as landfill or incinerated. Of this disposal quantity 96 percent is at present being incinerated.

Incineration is preferred for a variety of reasons such as minimized transportation costs, since landfills are frequently several kilometres away from the mill. Landfills also incur disposal fees, ongoing disposal area maintenance costs, potential fire hazard and represent potential long term environmental problems. At present the costs of disposal favour incineration.

Transport Costs

Woodwaste may be transported to a process plant site by three methods.

1. Conveyors - belted conveyors are required for the 1-2 km distances typical of Williams Lake. Pneumatic conveyors are suitable only for processed woodwaste at distances less than 500 metres.

2. Railways - for long distance transport of woodwaste primarily from major single sources to the powerhouse. Rail loading and unloading facilities are costly and tend require dedicated car type and size.

3. Trucks - truck transport is the most flexible method of bulk material hauling and new woodwaste locations can be easily developed. The wood products trucking industry is well developed within the Region and should offer price-competitive and reliable service on a contract basis.

   Existing truck units used for chips and sawdust are ideally suited to woodwaste hauling. Typical semi-trailer or "B" train units will be used. Hydraulic truck dumpers accommodate complete units.

Woodwaste would be moved to the Williams Lake power plant by belt conveyor and by truck. Capital and operating costs have been identified and included in the study results for this configuration. Railway transport is an option but has not been included in the cost estimates as extended long haul movement of woodwaste to Williams Lake is unlikely.

The costs of woodwaste transportation has been evaluated based on estimates from project staff, truck transport and railway operations and is presented in Appendix 10, "Transportation Cost Data".

A summary of the average capital and operating costs of each option is presented below:

Table 8 - Typical Unit Costs of Woodwaste Transportation

Transport Mode	Cost M $/T
Belted Conveyor (2 km)	1.30
Truck - Semi Trailer (200 km)	10.00
Truck - "B" Train (200 km)	8.50
Rail - (400 km)	14.00

Based upon a 200 km round trip economic truck distance, the Cariboo Region woodwaste supply and distribution suggests two major haul centres, Williams Lake and Prince George, and two minor ones at Mackenzie and McBride. See Figure 1 - Potential Woodwaste Collection Centres. In every case the possibility of expanding the collection area is enhanced when backhaul, usually chips, provides transportation cost reduction of about 40 percent.

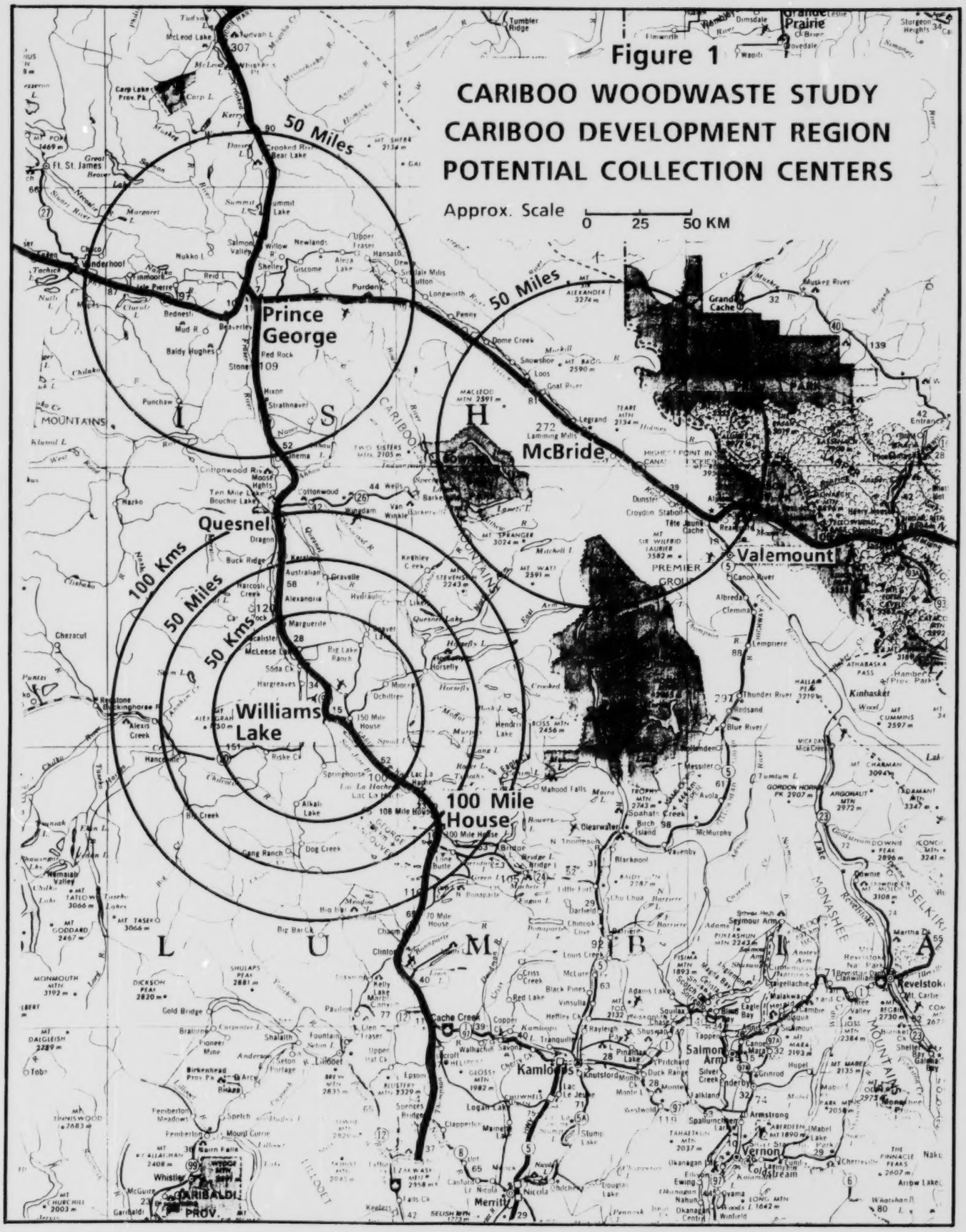
Figure 1
CARIBOO WOODWASTE STUDY
CARIBOO DEVELOPMENT REGION
POTENTIAL COLLECTION CENTERS
Approx. Scale
0 25 50 KM
50 Miles
50 Miles
100 Kms
50 Miles
50 Kms
Prince George
McBride
Quesnel
Valemount
Williams Lake
100 Mile House
Kamloops
Salmon Arm
Vernon
Merritt
Cache Creek
Grande Prairie
Grand Cache
Revelstoke
Whistler
GARIBALDI PROV.

Williams Lake is the principal woodwaste centre in the Region with approximately 293,000 BDUs within the city. Approximately 60 percent would be moved to the power plant by conveyor at an average cost of $1.30/T. The remaining 40 percent would come from the opposite end of the city by truck at a cost of about $2.50/T.

The relatively small quantity (10,500 BDUs) of wastewood at Lac La Hache could be shipped by truck. The woodwaste could be shipped to the power plant at approximately $4.00/T.

Cost of transport for woodwaste to Williams Lake from other locations have been estimated for various truck sizes and locations. Table 9 shows some typical unit costs.

Table 9 - Selected Transport Costs to Williams Lake

Woodwaste Location	$/T
100 Mile House (truck)	6.00 - 8.50
Quesnel (truck)	7.00 - 9.50
Prince George (train)	15.00

The truck transport costs presented above are used for thermal plant operating cost sensitivity analysis.

If local Williams Lake area sawmills are unable to provide sufficient fuel to maintain an 85 percent capacity factor, imported fuel is assumed to replace this fuel at a cost premium.

Operating economics of a 60 MW thermal plant requires fuel delivered at costs of approximately $8.00/T to produce electric power at prices 6¢/kWh or less. Using this criteria, 60 MW thermal plants could be located at Williams Lake and Prince George. Transport from distances over 200 kms (return) would require some subsidy to keep plant operating costs below 6¢/kWh.

Co-generation projects about one-half the size of that proposed for Williams Lake, if located in Mackenzie and McBride, could be served by truck. Rail transport remains an alternative. Because of higher capital costs of loading and dumping structures and inherent inflexibility, rail will not likely be an attractive alternative until hauling distances exceed 100 miles and volumes exceed 100,000 BDUs per year from a single source.

MARKETABILITY

General

The assessment of electric power markets available to a Cariboo Region power plant is based upon a review of current publications from B. C. Hydro and selected Western U.S. utilities. Meetings with B.C. Hydro power purchasing and planning staff were used as an opportunity to review and test conclusions.

With the exception of the Kootenay area of British Columbia, B.C. Hydro is the sole electric utility. Recent changes in B.C. Hydro policy have made the sale of privately produced power possible. As well, privately produced power can, under certain conditions, be wheeled (moved by transmission line) to other B.C. locations or to export customers in the U.S. The export sales will be sold through Powerex, a subsidiary of B.C. Hydro.

B.C. Hydro has transmission lines through most parts of the Region and the utility is essential to the successful development of electric power through direct sales and through wheeling. A summary of the B.C. Hydro "20 Year Resource Plan" is found in Appendix 9. The energy capability, and energy cost of the principal power sources are also listed.

Potential Customers for Electrical Energy

There are two other possible customers for electric power other than B.C. Hydro. These are, incremental new loads to industrial users in the Cariboo and export through Powerex to U.S. utilities.

Due to the relatively low volume based pricing structure of B.C. Hydro, the cost of electric power to most potential industrial customers is below a competitive rate from a single, relatively small thermal plant. The current lowest industrial rate is about 3¢/kWh assuming a 75% capacity factor. This rate is below B.C. Hydro's long-term marginal cost of 3.8¢/kWh in constant dollars.

B.C. Hydro may wheel power to industrial customers if capacity exists. The rates for wheeling are not yet established.

U.S. long term export opportunities exist in California and Utah. The Pacific Northwest does not offer much opportunity until about 2005. The relatively small (60 MW) energy potential and complex wheeling arrangements through B.C., Washington and Oregon make these remote markets unattractive.

Additional information on the industrial and export market opportunities are located in Appendix 9, "B.C. Hydro and Markets".

B.C. Hydro's Purchasing Policies

In December 1988, B.C. Hydro issued a policy regarding the purchase of electricity and load displacement from Independent Power Producers (IPP) in the integrated and non-integrated systems of the B. C. Hydro service area. "Integrated System" refers to the interconnected network of transmission lines and substations linking generating stations to one another and to customers of B. C. Hydro. "Non-integrated System" refers to remote service areas in B.C. Hydro's system where the generation, transmission, and distribution components of that isolated system are not interconnected with the B.C. Hydro main grid electrical power system.

B.C. Hydro intends to pursue cost-effective power purchases from IPPs. The IPP is a person or company whose independent generating facility is connected to B.C. Hydro's electrical system such that electricity may be sold to and purchased from B.C. Hydro. B.C. Hydro intends to use purchases from IPPs to defer more costly projects planned for B.C. Hydro's system. An IPP can also be an independent cogenerator power producer.

IPPs can serve the B.C. Hydro system at voltages of 60 kV or higher, or at a lower voltage distribution level.

B.C. Hydro intends to purchase power from IPP's assuming the cost of such purchases is less than the cost of power from B.C. Hydro's alternative sources. B.C. Hydro's need for new resources and the cost of those new resources are outlined in the description of B.C. Hydro's 20-year resource plan in Appendix 9.

For projects in the integrated system under 5 MW, B.C. Hydro will establish a fixed purchase price to minimize transaction costs. The purchase price will be based on B. C. Hydro's short-term and long-term marginal costs. For a 20-year purchase beginning in 1989, B.C. Hydro would pay 3.0¢/kWh.

For projects in the integrated system over 5 MW, the purchase price will be negotiated. The purchase price is expected to fall between B.C. Hydro's short-term and long term marginal cost of electricity and will reflect the values of firm and secondary energy. Depending on negotiations, the purchase price could be a levelized price that remains constant for a period of years or a ramped price that tracks B.C. Hydro's marginal cost. B.C. Hydro's long-term marginal cost is estimated to be 3.8¢/kWh in 1988 Canadian dollars. Assuming this rate escalates at a rate of 5% per year, and using a 5% net discount rate, the 20-year levelized rate for the 1992-2011 period would be 6.3¢/kWh.

The effect of a levelized purchase price would be to front-load payments which would result in overpayments for electricity in the early years of the project life in exchange for underpayments in the later years. The present worth of front-loaded payments would be the same as the present worth of payments based on the projected marginal cost of power each year. For purchase arrangements based on front-loaded prices, B. C. Hydro will require performance guarantees to compensate for the risk of non-performance by a parallel generator in the latter years of the contract.

The purchase price can also be affected by the firmness of energy deliveries, reliability of supply, the duration of supply, and the impact of the generator on B.C. Hydro's transmission and distribution system.

In a non-integrated area, the negotiated purchase price will be based on the cost of B.C. Hydro generation in the remote area. Generally, a remote area is served by a diesel generating station. Negotiated prices are also likely to have a reliability component.

Requests for Proposals (RFPs) will be issued for IPP offers to supply. In December 1988, B.C. Hydro issued an RFP for 100-200 MW for the integrated system. A non-refundable application fee of $6,000 will be required with each proposal. B.C. Hydro intends to issue similar RFPs as required in accordance with the needs of its most recent Resource Plan. RFPs are expected to be issued annually over the next several years.

Responses to the RFP will be evaluated based on price, the amount of firm electricity, fuel type, location, dispatchability, reliability and contract terms. B.C. Hydro will then commence contract negotiations with the potential supplier(s) that has the best proposal based on this evaluation.

The procedure for reaching an agreement to sell electricity to B.C. Hydro begins with the RFP. B.C. Hydro will then review the proposal and comment on it, assuming the proposal meets the requirements of the RFP. A preliminary estimate of inter-connection costs

will be calculated followed by negotiation of the contract. B.C. Hydro will analyze and comment on the project design. An operating and maintenance plan will also be required. The project, along with the interconnection facilities, would be built and paid for by the IPP. Finally, the project would be commissioned and interconnected for delivery of electricity to the integrated system.

In order to assure that the project provides annual firm energy deliveries, the purchase price may be structured to encourage delivery of a pre-determined amount of energy each year. The IPP will be required to maintain a high capacity factor and a low outage frequency. In addition, generating plants must be designed to perform reliably for at least 20 years.

Socially Beneficial Projects

In the policy on the purchase of electricity and load displacement for the integrated system from projects greater than 5 MW, B.C. Hydro refers to special arrangements for certain projects. The policy states that B.C. Hydro will consider special arrangements for those projects which demonstrate new technology or promising significant environmental, social or economic benefits to the Province.

The special arrangements are not identified but could be a levelized rate calculated such that the present value of B.C. Hydro's cost is no more than the present value of estimated long-term marginal costs. The Williams Lake Project would provide specific environmental benefits by improving air quality in the Williams Lake area. Attendant co-generation functions would further qualify for the special arrangements.

Potential for Heat Sales

The potential for heat sales, as steam, hot water or thermal oil, is a function of proximity to users and production cost. Appendix 4 "Heat Quantities and Selling Prices" examines the impact of the relatively low current price of natural gas and the long-term prices which might prevail.

Present bulk natural gas prices of about $2.50/GJ will dominate the heating market especially where direct firing of the fuel is possible. Long-term trends will no doubt produce real increases in gas prices. For example, Inland Natural Gas price projections imply a 2-3 percent per year real increase in large industrial gas prices over the next 10 years.

Co-generated heat for drying purposes from a woodwaste fuelled plant requires gas prices between $3.00-$4.00/GJ to compete. Typically, one of the adjacent mills at Williams Lake would use about 3 percent of the thermal plant capacity.

Potential buyers of process steam from the thermal plant should find the co-generation prices very competitive. The opportunity for a forest product board plant at Williams Lake exists. If located in the B.C. Rail industrial zoned land adjacent or near the thermal plant, a substantial amount, about 20 percent of plant capacity, of process steam and heat could be sold. Moreover, this energy should command a price higher than the equivalent amount of electric power which would have been generated by the steam sales because of economy of scale and convenient supply.

In all cases heat sales reflect a direct reduction in the amount of electric energy available for sale. As B.C. Hydro and investors will be looking for long-term contracts, the co-generation arrangements should be concluded prior to concluding electric power sales contracts.

Low temperature heat removed from the condenser cooling water is available at no penalty to power generation. Indeed it may offer a modest reduction in plant cooling tower operating costs. This low temperature hot water can be piped efficiently up to four kilometres and costs little to extract from the thermal plant process. This heat will be attractively priced for commercial application such as green houses and public application such as swimming pools.

PLANT SITES

General

The general requirements for a woodwaste fuelled thermal plant are set out in Appendix 7 "Site Selection". These requirements are valid for virtually all potential locations in the Cariboo Region.

Williams Lake

Based upon the selection criteria set out in Appendix 7, a single general site has been identified. Figures 2 and 3 identify proposed the site and surrounding area.

The strategic benefits of the location can be summarized as follows:

1. Adjacent to three of five sawmills in the city.
2. Convenient transportation access for trucks with potential for rail.
3. Adequate city water supply and sewer connections are within 1000 metres.
4. Downwind from the city, based on prevailing winds.
5. Adjacent to a large industrial area of potential co-generation users.
6. Away from the major residential areas and about one kilometre to the nearest dwellings.

The area represents approximately 8 ha adjacent to 60 percent of the woodwaste production and possible co-generation heating users. The site is conveniently located close to the proposed northern arterial road and is about 250 m from a B.C. Rail spur line. Adequate capacity city water supply and sewer lines are within 1000 m of the south boundry.

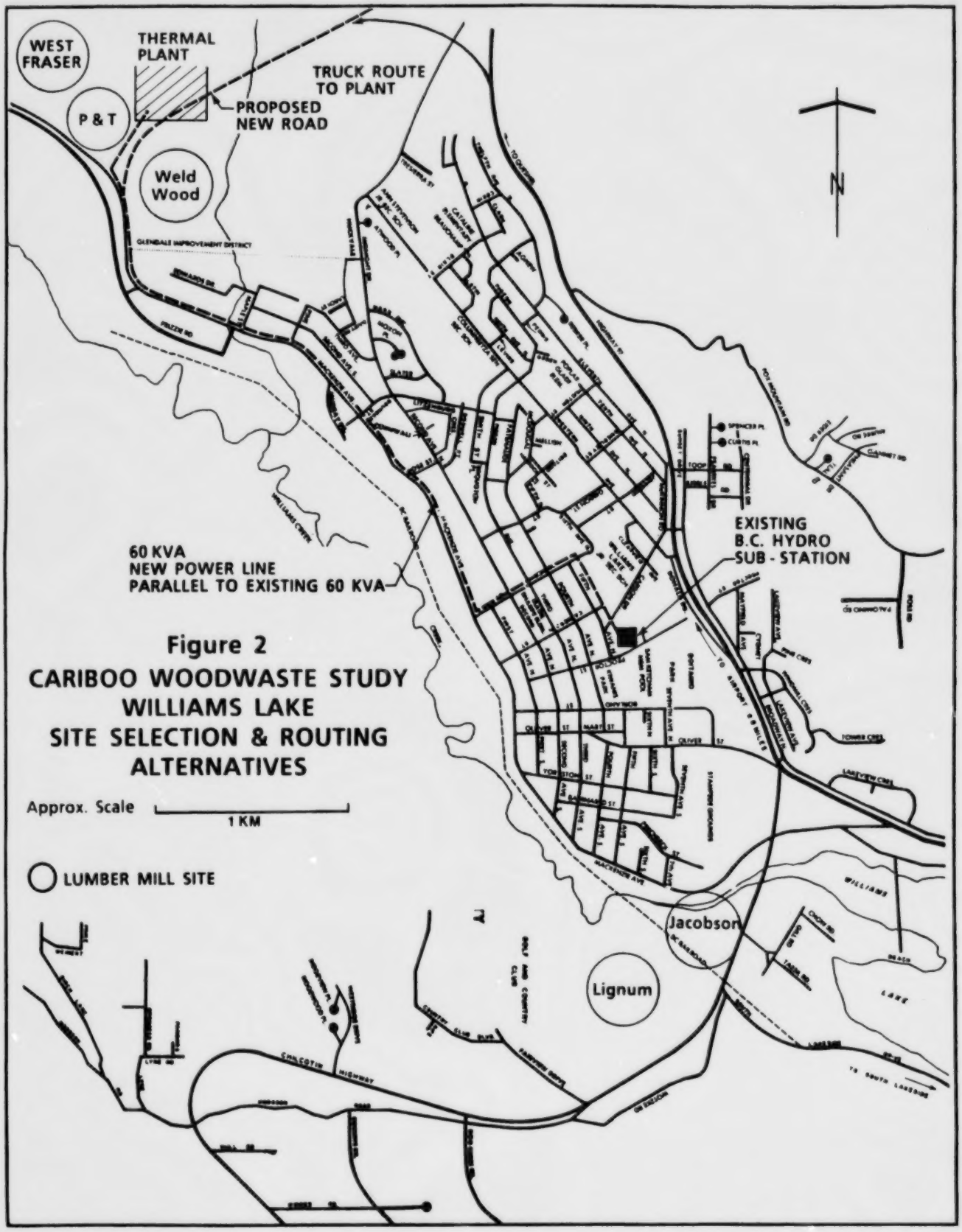

Figure 2
CARIBOO WOODWASTE STUDY
WILLIAMS LAKE
SITE SELECTION & ROUTING ALTERNATIVES

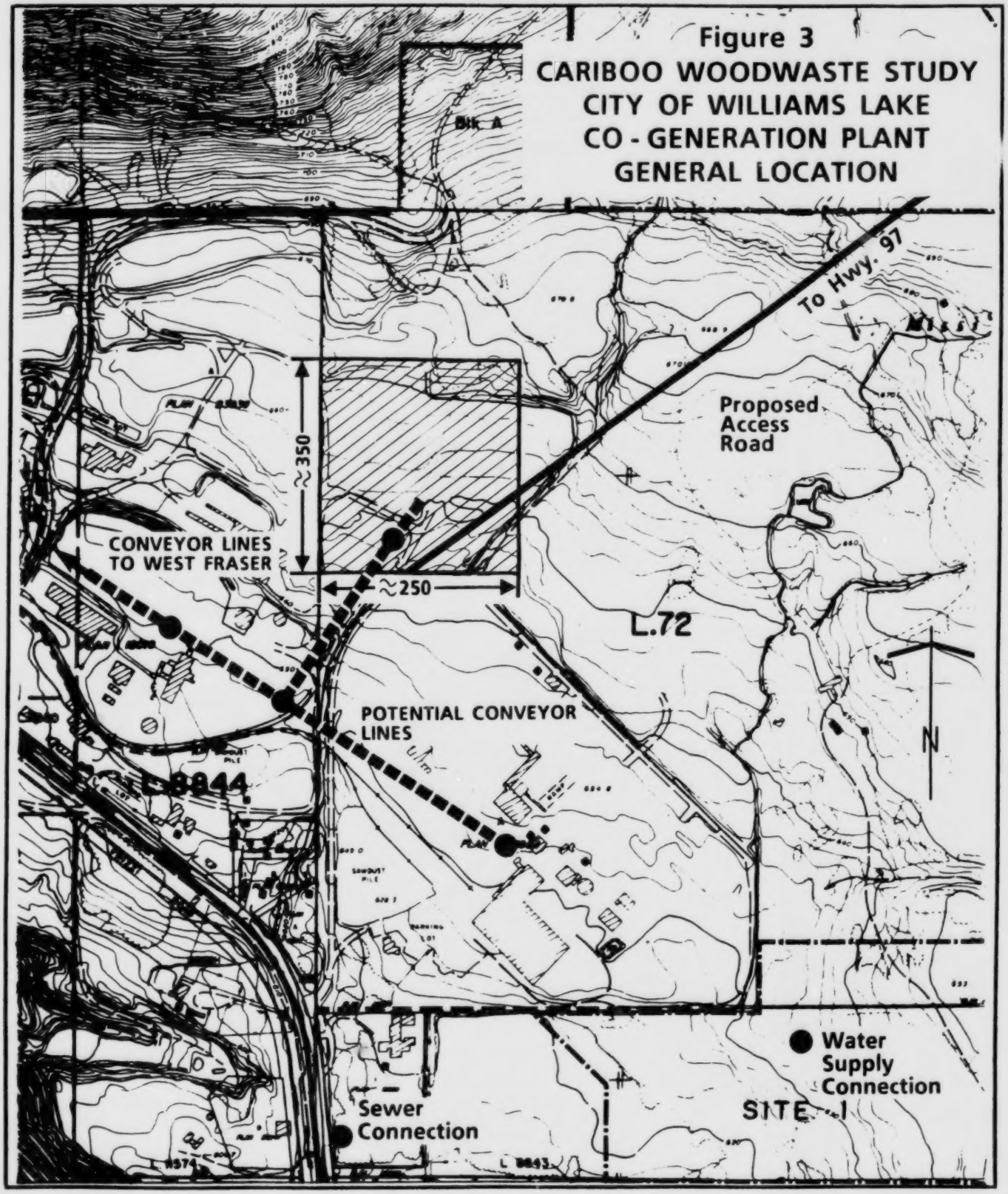
Figure 3
CARIBOO WOODWASTE STUDY
CITY OF WILLIAMS LAKE
CO - GENERATION PLANT
GENERAL LOCATION
To Hwy. 97
Proposed Access Road
≈350
≈250
CONVEYOR LINES TO WEST FRASER
L.72
POTENTIAL CONVEYOR LINES
L.8844
N
Water Supply Connection
Sewer Connection
SITE 1

POWER PLANT ENVIRONMENTAL CONSIDERATIONS

General

A Thermal Power Plant may be regarded as a black box which transforms its input streams of fuel, air and water into output streams of power, ash, combustion gases and effluent water. Consideration is given to the environmental impact of each of these streams as follows:

Water Usage

Water is required to make up for losses due to boiler and cooling water blowdown. This will be supplied from the city system which must be sized for the volumes required as detailed in Appendix 8. The water supply to the north end of the city should be upgraded according to the recommendations of the City's engineer.

Make-up water for the boiler must be demineralized or "softened". This is an ion-exchange process and will be conducted through two demineralizer streams to permit replacement of the resins and maintenance without interruption of the supply. The exact consumption rate of the ion-exchange resins will depend on the water composition.

Chemicals are subsequently added to the boiler water for control of oxygen content, pH and corrosion. Typical additives are detailed in Appendix 8. Boiler blowdown is required to prevent the concentration of dissolved solids in the feedwater and to maintain the effectiveness of the treatment. The chemical composition of this blowdown permits it to be discharged into the town sewage system.

Cooling water is required to condense the steam as it leaves the turbine. The water is circulated through the cooling tower, and a proportion is lost to the atmosphere by evaporation. In addition, a certain amount of cooling water is continuously removed to prevent the concentration of unwanted compounds. This water is referred to as cooling water blowdown. The cooling water is treated with chemicals to prevent scaling or deposition on the condenser tubing, or corrosion. The proposed treatment is a non-chromate process which permits safe discharge of the blowdown to city sewage.

Other sources of wastewater include sewage, floor washings, etc. Sewage will discharge with the above streams to the town systems. Floor washings which could contain oils, greases or other contaminants, will be directed to sumps and processed prior to discharge.

Stack Emissions

Stack discharge gases are principally composed of carbon dioxide, nitrogen and oxygen, smaller percentages of nitrogen and sulphur oxides, carbon monoxide and particulates. With the exception of the nitrogen and oxygen, each of these constituents has an environmental impact. Environmental guidelines for these emissions, as suggested by the Ministry of the Environment, are listed in Appendix 11. The technological implications of these guidelines are discussed as follows:

1. Nitrogen Oxides (NOx)

   This is formed by the combustion reaction of nitrogen contained in the incoming combustion air and the hog fuel, with oxygen. Nitrogen oxides react with

atmospheric water to form acidic compounds. Specialized methods of combustion are available which have the potential to reduce NOx formation. However, with this fuel, the boiler manufacturers contacted indicate that the environmental guideline level can be achieved. This may require closer consideration at any design development stage.

2. Sulphur Oxides

This is formed when sulphur in a fuel is burned. Since wood contains only trace amounts of sulphur, guideline levels can be achieved with no special measures. Substantial use of supplementary fuel such as coal, oil or gas would change this situation.

These oxides are similar to NOx in producing acid compounds where combined with atmospheric water.

3. Carbon Monoxide

This is a product of incomplete combustion and the existing combustion control technology will keep levels within environmental guidelines.

4. Particulates (Fly Ash)

The proposed design incorporates two particulate collection devices in series.

At the exit from the air heater the combustion gases pass through a bank of cyclones (multiclones) which capture the larger particles. After this the gases pass through a single or twin chamber electrostatic precipitator. In the precipitator the particles acquire a negative charge and are then collected on positively charged plates. These are vibrated or rapped to remove the dust from the plates; the dust then falls into discharge hoppers. Collection efficiency is high and achieves environmental guidelines.

The precipitator is comprised of 3 fields with a total collection area of 9,477 m^2. The overall efficiency is 98.9 percent and the anticipated emission level is the equivalent of approximately 260 kg/day.

A comparison of observed and estimated emissions is presented in Table 10. Ministry of Environment Survey data is available for 1985. The 1988 data is adjusted to account for increased incineration. The thermal plant data is consistent with the selected emissions control plant and recommended guideline levels.

Table 10 - William Lake Present and Forecast Air Emission Levels

	From Incinerators				From Thermal Plant	
	1985*1		1988*2		Future	
	t/a	kg/t (dry fuel)	t/a	kg/t (dry fuel)	t/a	kg/t (dry fuel)
Particulate	1335	7.0	2493	7.0	70	0.22
Sulphur oxide	19	0.01	35	0.01	31	0.01
Nitrogen oxides	191	1.001	356	1.001	707*3	2.2
Non-methane hydrocarbons	2098	11.00	3917	11.0	223	0.70
Polynuclear aromatic hydrocarbons	191	1.001	357	1.001	0.3*4	0.02
Carbon monoxide	24,791	130.0	46,296	13.0	20	0.06

*1 1985 data from Ministry of Environment Survey
*2 1988 data extrapolated for increased waste incineration
*3 Corresponds to guideline levels. Actual levels could be less according to selected combustion technology.
*4 Based on measured levels in fly ash sample and 20-fold concentration due to sub-micron particle size.

Ash Disposal

Ash is collected from the grate (bottom ash) and the airheater hopper, the multiclone and the precipitator (fly ash). If the ash from the airheater or multiclone contains a high proportion of carbon the carbon can be separated from the ash and reinjected into the furnace. The ash will be collected and conveyed to a central storage bin and truck hopper for discharge to landfill.

An analysis of typical fly ash was performed by the Waste Management Branch of the Ministry of Environment. This confirmed a design assumption that the ash would not be a "special waste" requiring additional landfill safeguard measures. The analysis and report are detailed in Appendix 12.

ALTERNATIVE PROCESSES

General

Although the study has concentrated on the provision of estimates and description of a conventional power plant, alternative conversion technologies exist which can provide both energy and product streams for revenue. These processes and associated plant will

require an increased level of engineering, entrepreneurial activity and co-ordination, and the time taken to develop a solution to the disposal problem is likely to be increased.
The concept design of a conventional power plant is presented in the general specification presented in Appendix 8, Power Plant Details. The alternative technologies are presented below along with preliminary assessments.

Prior Studies and Alternative Processes

Waste wood may be used as an energy source or as a source of secondary constituent products. In general, the technology of combustion and power production is conventional and established; risk is limited largely to economic considerations. Other conversion processes may imply both technical and economic risks which must be closely reviewed.

Conversion technologies were comprehensively reviewed in a study sponsored by Energy Mines and Resources Canada under the ENFOR (ENergy from the FORests) Program in 1983. This was carried out by Simons Resource Consultants and B.H. Levelton & Associates Ltd.[2] In nine volumes the report adopts a unit approach to conversion systems under the following titles:

Fuel Preparation and Handling
Storage and Reclamation
Handling
Comminution
Classification
Mechanical Dewatering
Thermal Drying
Densification

Primary Conversion by Direct Combustion
Steam Generation
Hot Gas Generation

Primary Conversion by Thermal, Chemical and Biological Methods
Gasification
Pyrolysis
Direct Liquefaction
Hydrolysis of Biomass (wood) to Sugars
Fermentation to Alcohols

Modification and Upgrading of Energy Forms
Removal of Particulate
Removal of Condensible Material
Fuel and Synthesis Gas Upgrading
Alcohol Separation

Pollution Control
Environmental Regulations
Summary of Discharge Characteristics
Pollution Control Unit Processes

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[2] Enfor Project C-258. A Comparative Assessment of Forest Biomass Conversion to Energy Forms. Energy, Mines and Resources Canada, December 1983.

Secondary Conversion of Energy Forms
Steam Generation from Fuel Gas and from Hot Gas
Heat Exchangers
Mechanical and Electrical Power Generation
Steam Turbines
Internal Combustion Engines
Gas Turbines
Steam Engines

Systems for Utilization of Biomass Fuels
Kiln Drying of Lumber
Production of Wood Fuel Pellets
Furnish Drying
Cogeneration of Steam and Electricity
Generation of Electricity using a Gasifier
Firing of a Lime Kiln
Ethanol Production by Hydrolysis of Wood with Sulphuric Acid

The conversion processes are summarized in Figure 4. This report provides valuable source material for the consideration of alternatives to conventional power generation, and combinations of the listed processes may be applied according to perceived market demand.

The following examples are typical of recent technology.

1. Explosive Decompression

Explosive decompression subjects the biomass feedstock to high pressurization within a digester vessel. The stock is then abruptly exposed to atmospheric pressure. The process breaks down biomass into its three major components, cellulose, hemicellulose and lignin. The wood constituents are then subjected to other processes which are known and available. The explosive decompression process may be considered as a pre-treatment stage in the hydrolysis processes, or as a primary process for pulp production.

The wood constituents may be utilised for the following range of products:

Cellulose:
- Glucose
- Ethanol
- Single cell protein
- Cattle feed

Hemicellulose:
- Furfarol (petrochemical refining solvent)
- Xylitol (pharmaceutical and food sweetener)
- Lignins: wood products adhesive
- Lubricant and sealant in drilling muds
- Carbon blacks
- Engineered plastics
- Specialty dispersants

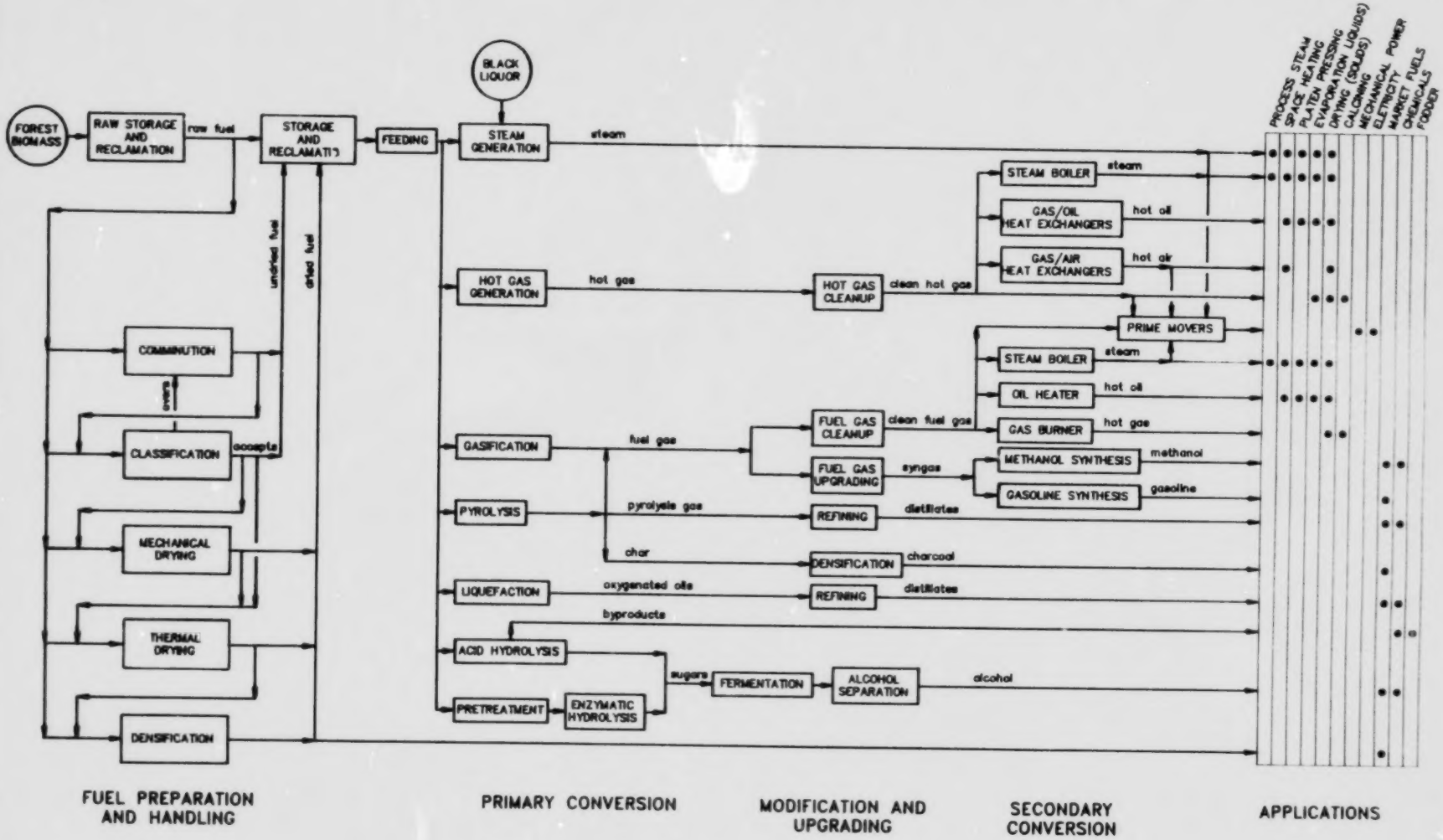

FIGURE 4 UNIT PROCESSES AND SYSTEMS FOR CONVERSION OF FOREST BIOMASS TO ENERGY FORMS

FROM: ENFOR PROJECT C-258
"A COMPARATIVE ASSESSMENT OF FOREST BIOMASS CONVERSION TO ENERGY FORMS"

CAD FILE NO. 7701-002

All:
Pulp production

The technology has been applied only to hardwoods at this time. Cattle feed from softwoods is not sufficiently high in cellulose content to permit sustained growth.

Aspen pulp is to be produced in Meadow Lake, Saskatchewan, by Nortek Forest Products under a project sponsored by the Government of Saskatchewan. The production volume is to be 110,000 T/y.

The applicability of the process to softwoods is indeterminate at this time and would require development. Considering the type of waste available in Williams Lake, explosive decompression does not warrant further consideration in this study.

2. Co-production: Gasification and Pyrolysis

A combined gasification and pyrolysis plant could be capable of producing upgraded fuel (pellets or carbon), derived chemicals and energy, depending on the combination of unit processes, and the perceived marketability of the products.

Gasifiers are classified as updraft, downdraft, stirred bed or fluidized bed.

Updraft gasifiers produce a tar-laden product which must be immediately combusted in, for example, a boiler furnace if further processing is to be avoided. Present technology limits their application to 4 ODt/h.

Downdraft gasifiers produce a much cleaner product as the tars are drawn through the char bed and "cracked" to produce a higher gas yield; however, output is restricted by gas velocities in the throat area and outputs are restricted to 1 or 2 ODt/h. In addition close control is required of particle size and moisture content; for this reason a pre-treatment process such as drying and pelletisation may be required. Drying can be accomplished with stack gases at a boiler or gas turbine exit. Pelletisation requires use of a proportion of the generated power at the expense of revenue.

Fluidized bed gasifiers are not subject to these limitations and can therefore operate with wider applicability; capacities are higher and offer a better fit to the projected unit capacity of 40 ODt/h. Gas cleanup and pressurization would be a consideration if the gas were to be supplied to a prime mover such as a gas turbine or engine. The gas may however be fed directly to a boiler furnace for steam power generation.

Gasifiers may be pressurized and the products (char, tar and gases) reacted with steam and oxygen to provide a raw synthetic gas for further processes similar to those currently used in the petrochemical industry. End products could be methanol, ammonia or other chemicals. The production of ethylene is also possible.

The viability of a co-production plant requires more investigation than is possible within this study; the location and security of markets will be critical and these factors will present a continued risk to economic viability throughout the life of the project. The products are not likely to be competitive with those derived from feedstocks available in the petrochemical industry.

3. Conversion to Building Materials

Shavings may be converted to pressed board; the demand for board is subject to market forces and diversion of the shavings for this purpose could be performed by the mills themselves if it is perceived as profitable.

Patent processes are available which provide an inorganic matrix to bind biomass fibre into useable products such as board, building blocks, shotcrete or expanded rigid foam.

The techniques are available for a proportion of the waste to be disposed of in one or more of these forms. However the total disposal problem is unlikely to be addressed in the immediate future by any entrepreneurial group except as a co-generation facility with power sales as a secondary aspect of economic feasibility. This concept is discussed below.

4. Co-generation

When the steam produced is used to provide heat to a process as well as for power, the system is said to be co-generating.

In 1980, Intercontinental Engineering Ltd. produced "A Study of Cogeneration in British Columbia"[3] for a group comprised of BCHPA, the BC Energy Commission and the Council of Forest Industries. The production of power and process steam by the British Columbia pulp and paper industry was examined The study determined whether existing pulp mill steam generating plants could provide significant cost-effective increased power in the province, and included a consideration of the economics of increased hog fuel burning. Conclusions were generally pessimistic as to both the amount of power and the costs. There are no pulp mills in the immediate vicinity of Williams Lake so potential for waste disposal by this method does not exist. The nearest mill is at Quesnel which presently consumes about 30% of that area's production of woodwaste.

Despite the above, the possibility of the installation of any plant or facility with energy requirements should be thoroughly investigated; the proximity of a thermal plant could serve as an incentive for development. A likely candidate could be a plant for the manufacture one of several types of particle board. Such plants require process steam, heat, and power, each of which can be provided.

The provision of heat for greenhouses is possible with the proposed plant and would utilize the low temperature condenser cooling water. This heat would otherwise be rejected directly to atmosphere via the cooling tower.

Heat may also be provided to lumber dry kilns in the vicinity. In this case high pressure steam would be extracted from the turbine and a heat exchanger used to heat thermal oil or hot water/glycol for circulation to the kilns.

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[3] A Study of Cooperation in British Columbia B.C. Hydro and Power Authority, B.C> Energy Commission, Council of Forest Industries, 1980.

The provision of co-generation facilities has a significant effect on project economics and it is recommended that co-generation possibilities be thoroughly investigated with potential users prior to a design development stage. The economics must be considered in conjunction with potential social benefits including increased employment.

Disposal Methods

Waste disposal may be accomplished in whole or in part by one or more of the following methods.

a. Landfill

A 20 year supply of woodwaste based on the Williams Lake study data if placed in a landfill site to a depth of 6 m would cover an area of 2.6 km square or 680 hectares. The area would be unavailable for other uses until eventual aerobic decomposition of the upper surface could produce a viable topsoil. Environmental concerns would include spontaneous combustion and leaching of constituent organic and inorganic compounds to the surroundings. The dump or dumps would represent a continued cost to the community but would immediately alleviate the current atmospheric pollution associated with current incineration practices. Landfilling would be consistent with current concerns to reduce carbon dioxide emissions with regard to global warming. In the event of marginal economics of a power plant or an associated lack of entrepreneurial capital, this could be a least cost option.

b. Incineration

The elimination of present mass burning in wigwam or teepee incinerators has been considered the prime objective of this study. Incinerators cannot meet environmental standards without clean up equipment which implies cooling of the combustion products.

Continued mass burning has therefore not been further considered in this study.

CAPITAL COST ESTIMATE

Summary

Capital costs for the Base Case and Option A plans are summarized in Table 11 and presented in detail in Appendix 3.

Table 11 - Capital Cost Summary

Item	Estimated Cost $ '000' 1988 Base Case	Option A
Plant Capital		
- Structures	19,655	19,727
- Equipment	71,884	66,764
- Heat Supply to Sawmills	1,600	1,600
- Indirect Construction Cost	2,260	2,260
- Engineering	9,000	9,000
- Contingency	9,500	9,500
- BCHPA Utility Tie	1,240	1,240
Total Plant Capital	115,139	110,091
Pre Operating Expense	4,030	3,853
Total Capital Costs (excluding interest during construction)	119,169	113,944

Basis of Capital Cost Estimates

1. General

The estimates are substantially based on previous studies, revised to account for design changes and escalation of material and labour costs.

The cost estimates provide for the direct payroll cost of labour and tradesmen up to foreman level and the direct cost of material, including freight, duty and applicable taxes. The estimates also include the cost of the contractor's overhead or fees and other costs directly applicable to labour.

2. Structures

The estimates for site work including site grubbing, levelling and grading, fencing, water supply and effluent disposal have been included under Structures in this summary. The estimates for these have been based on presumed sound soil conditions which will have to be confirmed for a more definitive estimate.

All cost estimates for site services were based on a take-off of quantities and on current cost records from similar projects.

All building structural cost estimates have been based upon assumed soils data and preliminary structural designs from which the required quantities of materials have been estimated. The unit prices for the various items of work have been obtained from current files.

The structural estimates include not only the basic structure but also interior fire protection, including sprinklers where necessary, building heating and ventilating, lighting, plumbing and painting. The allowance for painting includes the painting of all equipment.

3. Equipment

The cost of major items of equipment has been based on written estimated prices received from suppliers. For auxiliary equipment such as pumps, estimates have been based on verbal cost data provided by equipment suppliers. For items such as pipe, valves, process controls, electrical equipment, insulation and tanks, allowances have been made on the basis of cost data obtained from Sandwell's records for similar current projects, checked with the data from suppliers. Equipment for "black start" capability including a diesel generator, has not been included.

The cost of installation labour, where not quoted by equipment suppliers, has been based on Sandwell's manhour records. Labour costs are based on a 37.5 hour workweek, with premium time labour identified separately.

4. Indirect Construction Cost

The indirect construction cost estimates have been based upon information from other projects of a similar nature. The estimates provide for such administrative items as the cost of management, trade superintendents, construction engineering and surveying. The estimates also provide for the cost of all temporary structures and services such as winter heating of buildings, water, fire, electrical, and sanitary facilities, and for the provision of some construction equipment for the execution of the work.

No provision has been included for a construction camp.

5. Engineering

The cost of engineering has been estimated to provide for:

- The design development phase which includes the calling of tenders for all major items, the selection of equipment, the completion of flow diagrams and general arrangement drawings, and the preparation of a construction budget.

- Detailed design and drafting, which includes the preparation of all detailed drawings, specifications and purchase orders required for appropriate contracts.

- Expediting of all drawings and data from suppliers to permit engineering schedules to be maintained.

- Resident engineering and inspection supervision of construction work together with a continuous cost recording system.

6. Contingency

The estimates described above are based upon engineering designs developed for this project and upon estimating prices for most major items of equipment. On this basis the estimates are sufficiently accurate to serve their purpose in providing a basis for the total cost. However, it is customary, and experience has shown that it is necessary, to provide a contingency allowance to cover items unforeseen at the present time, the need for which may become apparent as detailed design and construction proceed. The amount of this contingency allowance is a matter of judgement, and in this instance it has been considered prudent to include a sum equal to approximately 9 percent of direct structural, equipment and overhead costs.

7. Working Capital

Working capital estimates provide for capital invested in inventories, accounts receivable, pre-paid expenses and a cash reserve. The amount of current assets is partially offset by accounts payable. Inventories include 2 weeks' supply of hog fuel and 3 months' inventory of other materials.

8. Pre-Operating Expense

The estimated pre-operating expense covers all costs incurred prior to start-up such as for personnel salaries, wages and expenses, insurance, property taxes and supplies required for start-up.

9. Interest During Construction

Interest during construction has been included as an expense and is not capitalized.

10. Exclusions

It should be noted that the estimates do not include townsite or housing facilities.

OPERATING COST ESTIMATES

Summary

Detailed estimates of operating costs for the plant operating at nominal capacity are presented in Appendix 2, and summarized in Table 12.

Table 12 - Summary of Annual Operating Costs

Item	Amount ($ 000) Base Case *Alt 1	**Alt 2	Option A
Woodwaste	1,315	1,737	434
Other Materials	1,400	1,400	1,400
Ash Disposal	309	309	309
Make-up & Blowdown	450	450	450
Salaries and Wages	2,129	2,129	2,129
Administration and Overhead	1,750	1,750	1,750
Supervision Expense	Incl	Incl	Incl
Contingency	367	388	377
Total	7,722	8,164	6,850

* Assumes conveyored woodwaste from adjacent sawmills.
** Assumes all woodwaste trucked from sawmills.

The economic analysis considers the variation of net available power with load factor. The net power for the Base Case is lower than Option A to provide for the load of conveyors and increased hogging. The energy availability per annum is summarized as follows, accounting for station power requirements.

Table 13 - Summary of Energy Availability

Item		Base Case Alt 1 and Alt 2	Option A
Gross Electrical Energy	MWh/a	525,600	525,600
Net Electrical Energy	MWh/a	465,000	469,000

Basis for Estimates

The annual consumption of hog fuel is just over 2 million m^3. For the base case it is assumed that the cost of hogging the waste is charged to the project. For Option A it is assumed that conditioned fuel is received at the plant site and hogging is required for random oversizes only. The fuel costs are summarized in the following:

Table 14 - Summary of Hog Fuel Costs

Item	Amount ($ 000) Base Case Alt 1	Alt 2	Option A
Trucking	428	1,071	0
Conveying to Mill	261	0	0
Conveying at Mill	162	202	202
Cost of Hogging	465	465	232
Total	1,316	1,737	434

The ash disposal cost on Table 11 includes the operation of a truck, a contractor's fee, and an allowance of $15,000 per annum to cover disposal fees at the City land fill area. The contract would probably be part of the hog fuel haulage contract.

The cost of other material includes allowances for operating supplies, maintenance materials, diesel oil and natural gas for start-ups, periodic inspections and overhauls.

The estimated costs of salaries and wages for the plant have been based on manning levels in effect in steam and power plants in the wood pulp industry. Rates of pay are those in effect under the current labour agreements. The estimated costs include indirect expenses, such as health and welfare, workers' compensation, unemployment insurance, paid vacations and public holidays.

An annual allowance has been made for property taxes in the amount of $1,300,000.

General plant overhead expense includes allowances for communications, general supplies, purchased services, snow removal and miscellaneous expenses.

FINANCIAL ANALYSIS

General

As a multi-purpose project, the proposed facility must meet expectations for economy, flexibility, environmental improvement, appropriate investor return and long-term sales of electric power and heat.

Two basic project alternatives have been examined. A base case assumes a single project encompassing virtually all the costs and infrastructure required to move and prepare wastewood for plant fuel use. Another case examines the economics of a "stand alone" plant receiving woodwaste prepared elsewhere for fuel use.

The sensitivity of the rate of return on equity (ROE) to selected variables has been prepared to enable the reader to appraise the impact of changing conditions. The selected varables are:

- selling prices
- interest rates
- plant capacity
- debt/equity ratio
- fuel costs
- non-fuel operating costs
- capital costs

Analytical Approach

Forest industry and utility experience indicate that the commercial viability of independent plants producing electric power and steam for commercial heating from wastewood are usually tenuous. Consequently, long-term contracts for energy purchases from reliable fuel sources require detailed economic evaluation. This analysis provides the first pre-feasibility appraisal of the project.

Real rates of interest and return on equity have been chosen for the analyses since long-term contracts, typical of utilities, are likely to prevail. Terms of 20 and 30 years were chosen as appropriate time horizons. Since un-inflated target returns have been set as selection criteria, no inflation increases were added to costs or to revenues. This approach is appropriate because maximum long-term real returns are the investor's objective and attempts to account for short-term periods of relatively high inflation tend to obscure rather than clarify investment evaluation.

The model used for the analyses establishes the projected ROE for selected energy selling prices of electricity and of heat.

Interest during construction for this analyses is expensed; therefore project capital cost represents design, construction and management costs only.

Cases Studied

Two cases have been selected to reflect two capital and operating cost scenarios. The first case reflects a maximum level of plant responsibility and investment and is considered the Base Case. Woodwaste would be obtained by the plant operation from local sawmills and from regional sources if required. Woodwaste would be hogged as part of the plant fuel handling process. Trucks and conveyors would also be plant operated. A second case views the plant as a stand alone unit with the costs of transporting hog fuel and centralized hogging being borne by others. Woodwaste in prepared fuel form would be delivered to the plant. This case is referred to as Option A. Both cases assume long term sales and fuel delivery contracts.

The incremental capital and operating cost implications of meeting the new British Columbia air emission guidelines were found to be not more than 0.5 percent of total capital costs and therefore do not warrant special evaluation.

A thermal plant significantly larger (approximately 140 MW) was originally suggested by the study terms of reference. This case was rejected at an early stage of the study. Lack of sufficient long-term woodwaste fuel within an economic haul distance (about 50-80 miles) precludes viable operation of a larger plant.

Base Case - Description

The Base Case plant with its ancillary 1500 T/day hogger and conveyors from the adjacent mills is described in some detail under Appendices 2, 3 and 8. The trucking component of local fuel delivery is assumed to be sub-contracted by the plant operators.

The Base Case evaluation also considers the merits of using conveyors rather than trucks for moving material from the adjacent mills. Conveyors are demonstrably more cost effective despite estimated capital costs of $5.67 million.

Capital costs used for this case are summarized in Table 15 below:

Table 15 - Base Case
Capital Cost Summary
($000)

Expenditure Category	Structures	Equipment	Total	Total*
Plant Items Summary	19,655	71,884	91,539	112,299
Owner's Construction Overhead			2,260	
Engineering			9,000	
B.C. Hydro Connection				
Transmission Line			500	500
Substation			740	740
Co-generation Heat Connections			1,600	1,600
Contingencies			9,500	
Total Plant Capital Cost			115,139	115,139
Pre-Operating Costs			4,030	4,030
Total Capital Cost			119,169	119,169

* Total Capital Costs including related overheads.

Electric power is assumed to be sold on long-term contract to B.C. Hydro. Net energy available from the plant is estimated to be 394,836 MWh assuming an 85 percent capacity factor. The pricing for heat energy is based upon natural gas as the competitive fuel alternative as discussed in Appendix 4 "Heat Quantities and Selling Prices".

High temperature heat is assumed to command minimum prices of $4.00 per GJ on a long term basis. Current natural gas prices of $2.50/GJ are below this level but are expected to steadily increase, in real terms, over the next twenty years.

Option A - Description

The construction and operating scenario for this case is the same for the thermal plant and for fuel storage. Capital costs include a small on-site hogger to permit processing of woodwaste and frozen fuel as required.

No allowance has been made in the capital or operating costs for delivery of fuel from mills to the plant. Woodwaste would be received in hogged form ready for use similar to the Kettle Falls, Washington plant.

The capital costs for this case are summarized in Table 16 below.

Table 16 - Option A
Capital Cost Summary

Expenditure Category	Structures	Equipment	Total	Total* (incl OH)
Plant Items Summary	19,655	66,215	86,491	107,251
Owners Construction Overhead			2,260	
Engineering			9,000	
B.C. Hydro Connection				
Transmission Line			500	500
Substation			740	740
Heat Distribution (Co-gen)			1,600	1,600
Contingencies			9,500	
Total Plant Capital Cost			110,091	110,091
Pre-Operating Costs			3,853	3,853
Total Capital Cost			113,944	113,944

* Total Capital Cost including related overheads.

Electric power available for sale in Option A is estimated to be 399,336 MWh as power for a central hogger unit and conveyors would be purchased by the mill operators. Approximately 4500 MWh additional energy is credited to the project as well as a capital cost savings of $5,225,000. Pricing for energy is the same as in the Base Case.

Financing

The project financing is assumed to be made up of debt and equity. The proportion of debt to equity will ultimately be a function of the business risk perceived by lenders and investors.

Debt-Equity Ratio

The ratio of debt to equity for a business is normally determined by the market. Shareholders generally seek to maximize long-term debt because it is a cheaper way of financing a major project. Lenders, on the other hand, like to see significant equity in the project to reduce the risk of the company not being able to meet its debt service obligations. Businesses which are cyclical such as those in resource-based industries, generally carry a low debt-equity ratio. Utilities, which have stable and predictable revenue and cost inputs, generally have high debt-equity ratios.

This project has some utility attributes in that the technology for the conversion process is well-defined, and the revenue stream is likely to be secure by virtue of a contract with B.C. Hydro or another utility. The uncertainty is with fuel supply, that is, there

may be a need to draw woodwaste from a greater radius under certain conditions such as reduced lumber sales, labour unrest, etc. Having considered the financial risks associated with this project, a debt-equity ratio of 2:1 or 67 percent would appear reasonable. If the uncertainties associated with fuel supply can be resolved, or reduced to a relatively low level, the debt-equity ratio could be set at 3:1 or 75 percent debt.

Cost of Debt

Cost benefit analyses on major projects are normally carried out on a constant dollar basis, that is, inflation is assumed not to exist and real interest rates are used. Implicit in this methodology is the assumption that the business will take appropriate steps in negotiating long-term agreements and in making day-to-day pricing decisions to neutralize the effect of inflation. Also implicit is that actual interest rates fluctuate with inflation levels; that is, high inflation rates will result in high interest rates relative to the "real" rate.

Long-term real interest rates have traditionally fluctuated between 3 and 4 percent but in recent years they have drifted upward. Currently, long-term government bond yields are in the 10 to 10.5 percent range, which in relation to a 5 percent inflation rate suggests a real rate of 5 to 5.5 percent. As most economists believe that the current spread is anomalous, this analysis has been based on a real rate of 5 percent.

Rate of Return

In this analysis the rate of return will be the dependent variable, that is, revenues and costs will be set at rates which reflect market conditions and the return to shareholders will reflect project viability.

Based upon current market conditions, for projects of this kind, investors will be looking for a rate of return in the range of 16 to 20 percent on a pro forma basis. This level of return reflects some uncertainties which would normally be eliminated as the project is implemented. On an ongoing basis, investors would expect a nominal return in the order of 15 percent which corresponds to a real rate of 10 percent.

The ROE to the stockholders assumes a minimum of 10 percent real return. This return, therefore, sets the minimum selling price for electric power and heat from the plant. The impact on selling prices is also presented assuming that investors wish a 12 percent real ROE.

Sources of financing are assumed to be private. Three placements of debt and equity are scheduled to cover expected construction costs for each of three years. Capital will be required on the following schedule:

Table 17 - Schedule of Financing
($000)

	Year - 3	Year - 2	Year - 1	Start-Up
Base Case	11,917	47,668	54,585	0
Option A	11,394	45,578	51,972	0

Financial Support

The potential for assistance grants exist under different Federal, Provincial agencies and from B.C. Hydro sources. Sandwell has assumed that no grants or foregivable loans are available. Subsequent sensitivity analysis examines unit power price impact of grants between $5 to 10 million.

Fuel Costs

The annual consumption of woodwaste fuel is approximately 2,020,000 m^3 or about 515,700 wet T/A. Approximately 1,333,000 m^3 is produced from the three adjacent mills. This fuel can be either conveyored or trucked. All the remaining fuel, assuming normal mill production, will come from the two mills in the south of Williams Lake and will be trucked to the plant.

Unit costs for the transportation and preparation (hogging) of the woodwaste as fuel are shown in Table 18.

Table 18 - Fuel Delivery and Preparation Costs Per Tonne

	Units	100 Percent Truck	60 Percent Conveyor	Hogging	Cost of Fuel	
		(Alternative 2)	(Alternative 1)		(Alt. 2)	(Alt. 1)
Base Case	$/T	2.10	1.30	.90	3.00	2.20
Option A	$/T	0	0	.20	0.20	0.20

Hogging and rehogging of frozen fuel may be required for up to 20 percent of the fuel used in Option A as shown.

Conveyor system capital costs of $5,669,000 has been included in the materials handling portion of the Base Case capital cost estimate. The cost for trucked woodwaste will represent an operating cost only, because the task will be contracted out.

Adequate wastewood for fuel should be available on a long-term basis from present Williams Lake mills. Should supply fall short, due either to mill production cutbacks or partial removal of fibre quality white wood from the mill waste, woodwaste will have to be imported from other mills in the region. The most inexpensive sources are Lac La Hache, Quesnel and 100 Mile House in that order of preference. Quesnel is less expensive than 100 Mile House, despite the greater distance, because of the potential for haul-back by chip trucks operating from Williams Lake to the pulp mill at Quesnel. Details of the transportation costs are set out in Appendix 10 "Transportation Cost Data".

The impact of transporting relatively higher cost fuel to the plant from surrounding areas has been examined. Proportions of 10, 20 and 30 percent of the total fuel from from the surrounding region have been evaluated.

Woodwaste from the sawmills is assumed to be free in both the Base Case and Option A. Power cost effects are considered when a "disposal fee" is paid to the thermal plant to offset some of the plant's capital and operating costs.

Financial Report Format

The thermal plant cost and operations are represented within the framework of a financial model. A total of five reports comprise the output used for this evaluation. The reports are as follows:

- Income Statement
- Deferred Tax Calculation
- Projected Cash Statement
- Balance Sheet
- Cash Flow from Operations and External Cash.

Additional output data includes; loan amortization, and an itemized depreciation and capital cost allowance calculation for various classes of capital equipment.

A sample complete set of the report formats has been included in Appendix 5.

Results

As stated earlier, electric power selling prices (equivalent to project power costs) have been determined for the project. The prices were developed in order to yield a 10 percent real return on the 33 percent equity portion of the project financing. The required power price is 6.0¢/kWh for the Base Case and 5.6¢/kWh for Option A case. It should be noted that these prices are in 1989 dollars, but would not prevail until the plant is commissioned (earliest 1993).

If B.C. Hydro's currently stated pricing policy is used in the analyses, power sales would be set at 3.8¢/kWh and the resulting rate of return on equity would be only 3 percent in real terms. Such a low return would not be adequate to attract private investors.

However, if B.C. Hydro projects such as Keenleyside and Site C were financed and taxed on the same basis as that used for the Williams Lake thermal project the unit power costs are very similar. In other words the rates a private investor would need to charge for hydro power while achieving a 10 percent real return would be between 5-6¢/kWh.

The variables selected for evaluation of each case are those previously discussed and enable the reader to compare the two operating scenarios.

The expected value of each variable used in both cases is shown in Table 19. A summary of the projected results for a typical year (Year 9) is shown in Table 20 Income, Table 21 Balance Sheet and Table 22 Cash Flow.

Table 19 - Financial Projections - Base Value of Variables

Variable	Units	Base Value
• Capacity Factor	%	85
• Electric Energy Sales	%	96
• Heat Sales (proportion)	%	4
Heat Sales Price	$/GJ	4.00
• Fuel Source	% local	100
• Fuel Cost (local)(Base Case)	Wet T	1.00
(Option A)	Wet T	0
• Annual Operating Expense		
(Base Case)	$ million	9.0
(Option A)	$ million	8.3
. Capital Cost (Base Case)	$ million	119.2
(Option A)	$ million	113.9

Table 20 - Income Statement - Year 9

	Base Case ($000)	Option A ($000)
Operating Revenues	23,435	22,050
Cost of Sales		
Operating Expense	9,102	8,422
Operating Profit	14,333	13,629
Interest Expenses	1,942	1,857
Income (before tax)	12,391	11,771
Income Tax	5,755	5,468
Net Income	6,635	6,304

Table 21 - Balance Sheet - Year 10

	Base Case ($000)	Option A ($000)
Assets		
Current Assets	*64,915	*61,081
Net Property and Equipment	91,245	87,388
Total Assets	156,160	148,470
Liabilities		
Current Liabilities	1,013	939
Loans	38,849	37,146
Deferred Tax	34,697	32,725
Common Stock	39,723	37,982
Grant	0	0
Retained Earnings	41,878	39,677
Total Liabilities and Owners Equity	156,160	148,470

* Comprised of undistributed earnings, normally issued as dividends on an annual basis.

Table 22 - Cash Flow - Year 10

	Base Case ($000)	Option A ($000)
Net Income	6,635	6,304
Depreciation, Tax Effects & Accrued Tax	3,577	3,456
Tax	(6,461)	(6,116)
After Tax Funds before Changes in Working Capital	3,751	3,643
Changes in Accounts Payable (taxes)	5,780	5,270
Changes in Accounts Receivable	0	0
Cash from Operating Cycle	9,531	8,913
Less Capitalized Items	0	0
Cash before Financing and Interest Payments	9,531	8,913
Interest Expenses (A.T.)	(1,040)	(995)
Loan Repayment	(5,440)	(5,201)
Equity Cash Flow	3,051	2,717
• Debt/Equity Ratio	2:1	2:1
• Lending Rate	5% (real)	5%(real)
• Lending Term	15 years	15 years

To obtain the above results which reflect a 10 percent real ROE, the contract prices necessary from B.C. Hydro are shown in Table 23.

Table 23 - Projected Nominal Electric Power Costs

	1989	1993*
Base Case	6.0¢/kWh	6.5¢/kWh
Option A	5.6¢/kWh	6.1¢/kWh

* Potential first year of sales price at 4.5% inflation assuming 50 percent of plant operating cost is variable.

The price for electric power would be negotiated under some mutual agreement as to inflation and therefore future costs. First power delivery in 1993 reflects only an example of price escalation to that date.

As only a portion of the operating costs is subject to inflation, once the facility is constructed, the overall increase in selling price will need to reflect only that portion. For example, the total Base Case annual operating cost is approximately $9.0 million plus

interest (Yr-10) $1.6 million. Assuming 15 year term borrowing about 50 percent of the costs are fixed.

The financial evaluation indicates that the purchase price negotiated with B.C. Hydro will require approximately 1.8 to 2.2 ¢/kWh premium over the quoted long-term marginal cost to make the woodwaste-fired thermal plant financially attractive to private investors. This premium would apply to the values for the project variables, base value of the variables, as set out in the beginning of this section.

To enable an appreciation of how the amount of premium might change, sensitivity analyses have been prepared demonstrating the effect of key variables on the minimum selling price of electric power.

Sensitivity Analyses

The sensitivity of the selling price of electric power is demonstrated by changing selected variables while maintaining a minimum rate of return for both equity and debt investors on the project.

A summary of the sensitivity analysis shows the range of values in power cost and, more importantly, shows those variables which have the most impact on projected power costs.

Table 24 display a summary of these results for the Base Case. Figures 4 to 13 display the results of sensitivity analyses on the Base Case scenario.

Table 24 - Base Case Plant - Power Price Sensitivity

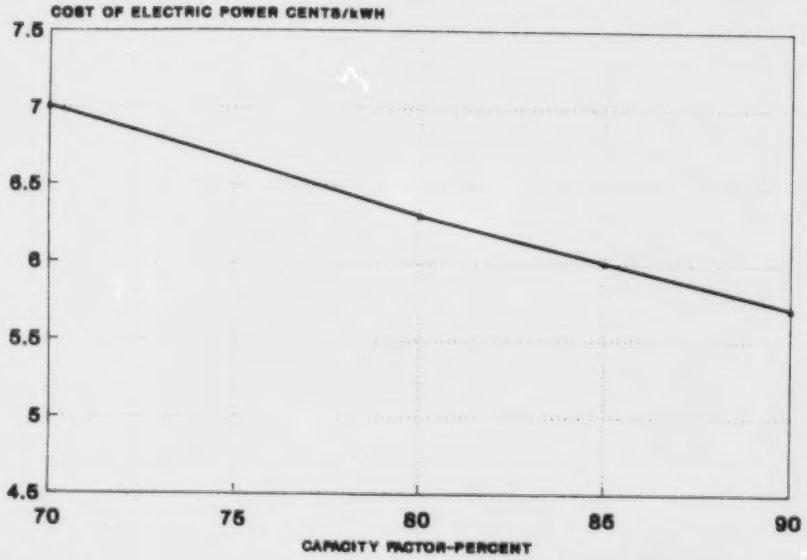
Key Variable	Units	Assumed Base Value	Change in Variable*	Corresponding Change in Price ¢/kWh
Capacity Factor	(%)	85	90 - 70	5.7 - 7.0
Electric Energy Sales	(%)	96	100 - 80	5.9 - 6.7
Heating Price	($/GJ)	4	1 - 8	6.1 - 5.9
Fuel Source	(% local)	100	100 - 60	6.0 - 6.4
Fuel Cost (local)	($/T)	1	**(-19) - 1	3.8 - 6.0
Fuel Cost (region)	($/T)	5	5 - 12	6.0 - 6.4
Operating Cost (variable)	$M	4.3	-10 - +10%	5.9 - 6.1
Capital Cost	$M	119	0 - + 20%	6.0 - 7.2
Debt Equity Ratio		2:1	4:1 - 1:1	5.2 - 7.5
Lending Rate	(% real)	5	5 - 9	6.0 - 6.4
Return on Equity	(% real)	10	10 - 12	6.0 - 6.5
Capital Grant	$M	0	0 - 10	6.0 - 5.1
Price ¢/kWh	6.0			

*Resulting price impact reflects change of the specific line variable only.

**Reflects fuel disposal fee charged sufficient to compare with B.C. Hydro long-term marginal cost.

Table 25 displays the results of sensitivity analysis on the Option A scenario. This table is supported by Figures 14 to 20 which graphically display the relationship of the variable and the selling price of power.

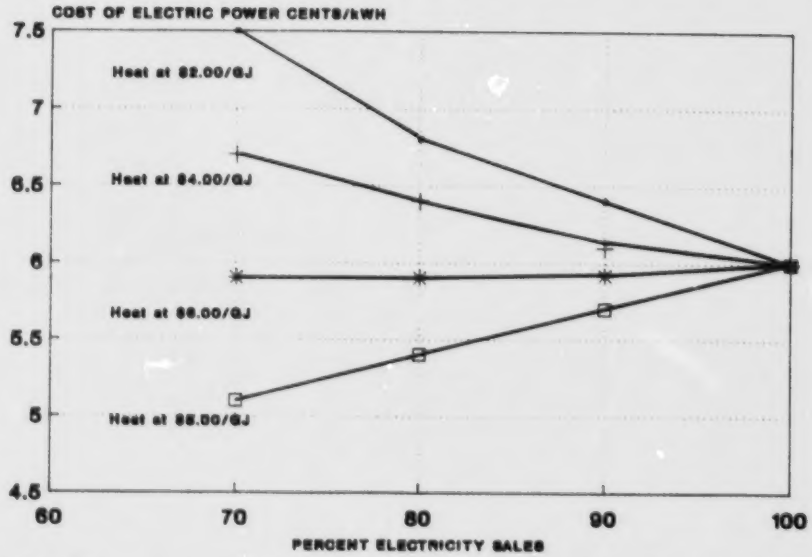
FIGURE 4



BASE CASE
VARIABLE -CAPACITY FACTOR

CARIBOO WOODWASTE STUDY

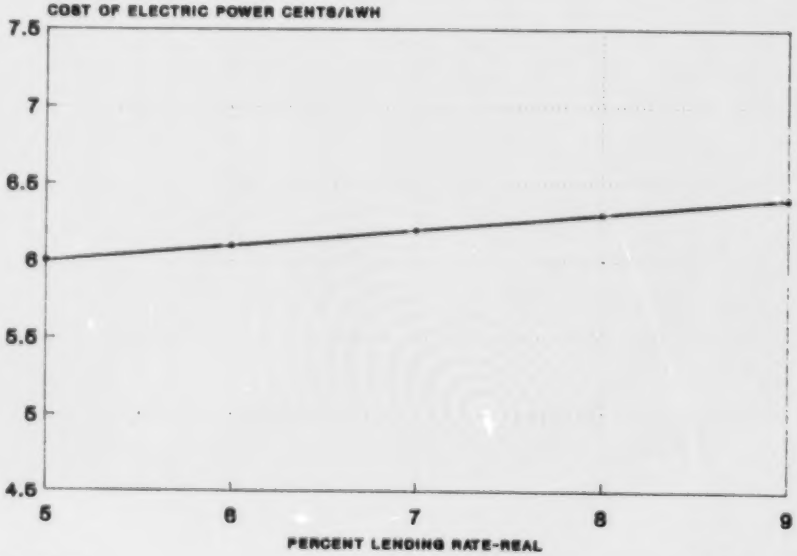
FIGURE 5



BASE CASE
VARIABLE -ELECTRIC ENERGY SALES

CARIBOO WOODWASTE STUDY

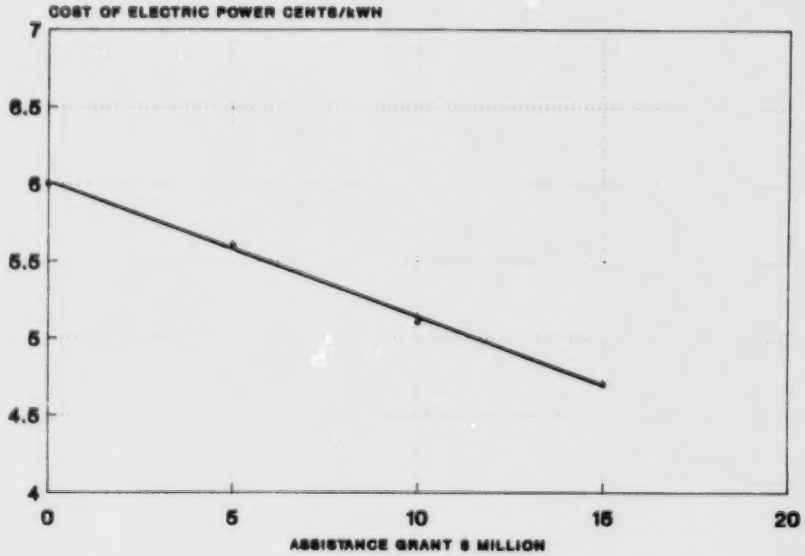
FIGURE 6



BASE CASE
VARIABLE -LENDING RATE

CARIBOO WOODWASTE STUDY

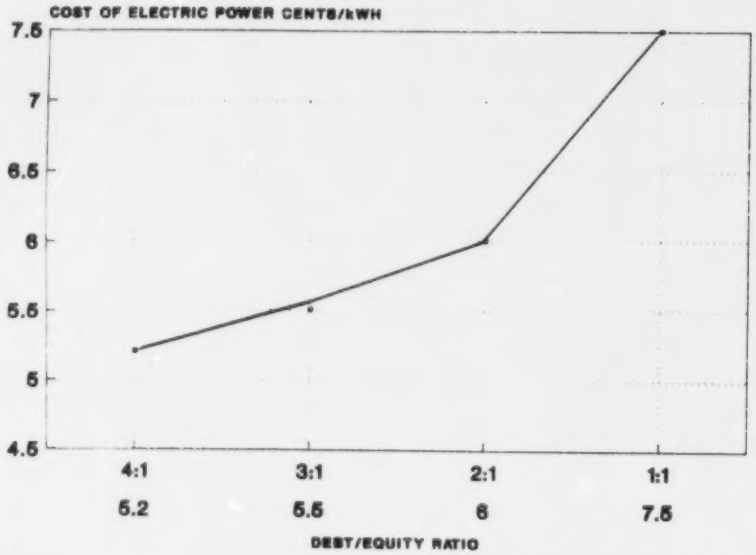
FIGURE 7



BASE CASE
VARIABLE -ASSISTANCE GRANT

CARIBOO WOODWASTE STUDY

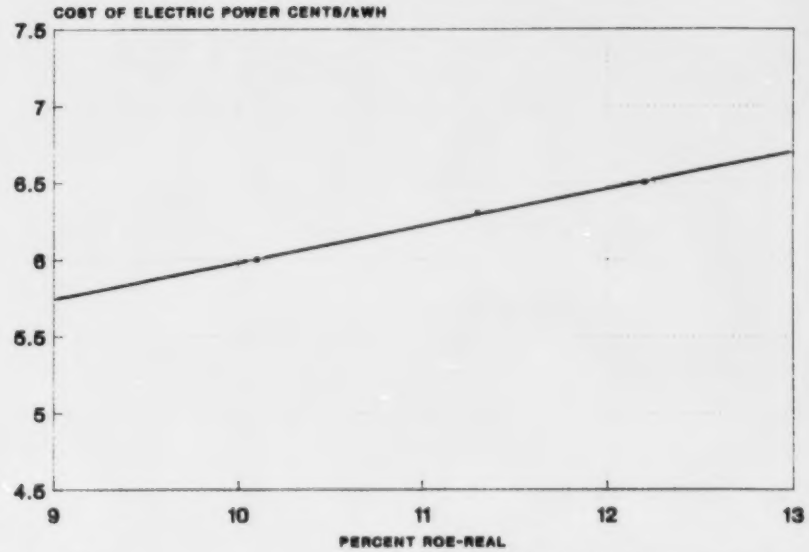
FIGURE 8



BASE CASE
VARIABLE -DEBT/EQUITY RATIO

CARIBOO WOODWASTE STUDY

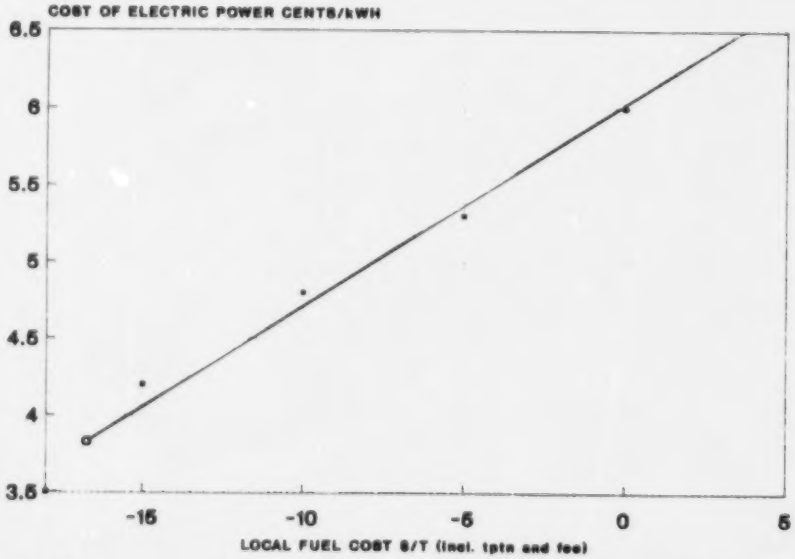
FIGURE 9



BASE CASE
VARIABLE -RETURN ON EQUITY

CARIBOO WOODWASTE STUDY

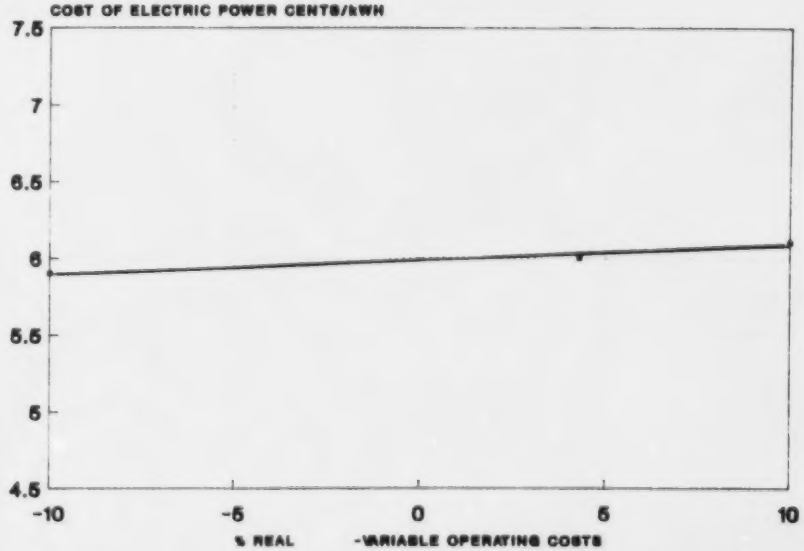
FIGURE 10



BASE CASE
VARIABLE -FUEL COST, LOCAL

CARIBOO WOODWASTE STUDY

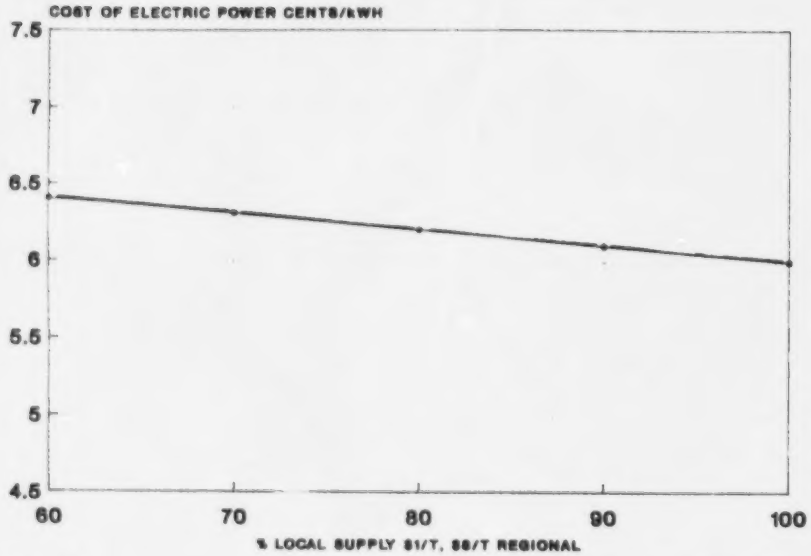
FIGURE 11



BASE CASE
VARIABLE -OPERATING COSTS

CARIBOO WOODWASTE STUDY

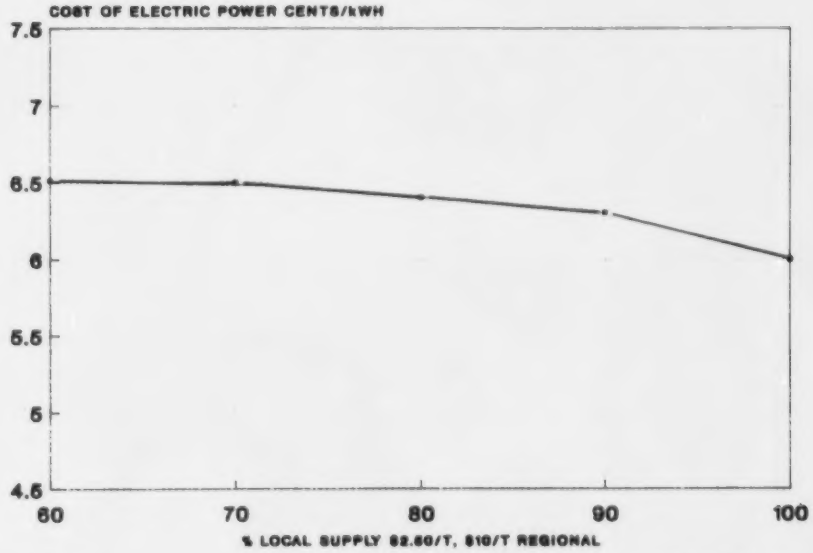
FIGURE 12



BASE CASE
VARIABLE -FUEL SOURCE

CARIBOO WOODWASTE STUDY

FIGURE 13



BASE CASE
VARIABLE -FUEL SOURCE

CARIBOO WOODWASTE STUDY

Table 25 - Option A Plant - Power Price Sensitivity

Key Variable	Units	Assumed Base Value	Change in Variable*	Change in Price ¢/kWh
Capacity Factor	(%)	85	90 - 70	5.4 - 6.6
Electric Energy Sales	(%)	96	100 - 80	5.5 - 6.2
Heating Price	($/GJ)	4	2 - 4	5.7 - 5.4
Fuel Source	(% local)	100	100 - 60	5.6 - 6.0
Fuel Cost (local)	($/T)	1	**(-15) - 0	3.8 - 5.6
Fuel Cost (region)	($/T)	5	5 - 15 @ 80% local	5.6 - 5.8
Operating Cost (variable)	$M	4.3	(-10) - (+ 10%)	5.5 - 5.7
Capital Cost	$M	119	0 - + 15%	5.6 - 7.1
Debt Equity Ratio		2:1	4:1 - 1:1	4.9 - 7.2
Lending Rate	(% real)	5	5 - 9	5.6 - 6.0
Return on Equity	(% real)	10	10 - 12	5.6 - 6.1
Capital Grant	$M	0	0 - 10	5.6 - 4.8
Price ¢/kWh		5.6		

*Resulting price impact reflects change of the specific line variable only.

**Reflects fuel disposal fee charged sufficient to compare with B.C. Hydro long term marginal cost.

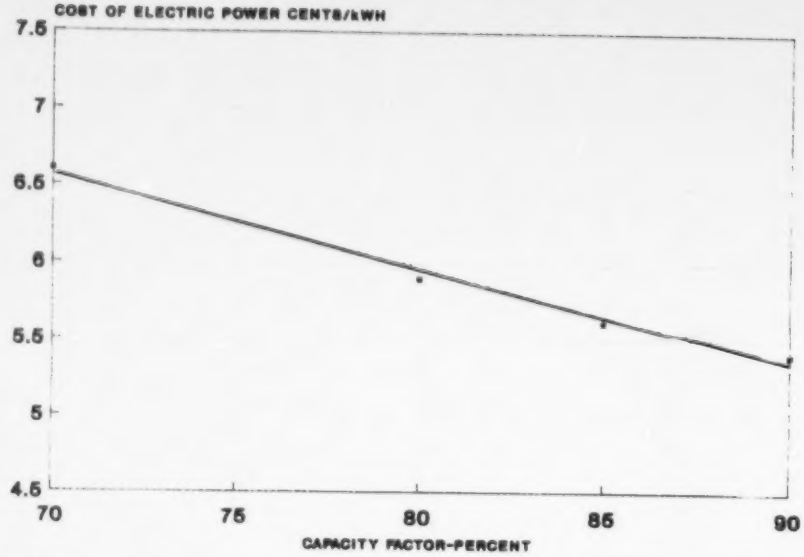
Discussion of Results

The sensitivity of the minimum prices required to meet investor expectations show both significant and relatively small effects from changing cost variables. Major items of concern are:

1. Capacity Factor - a reliably designed facility, adequate fuel storage areas and a firm "base load" generating contract are important to avoid power costs over 6¢/kWh or reduced investor returns.

   Experience from other wood waste plants shows that an 85 percent capacity factor is achievable. In the early years of operation the rate should approach 90 percent.

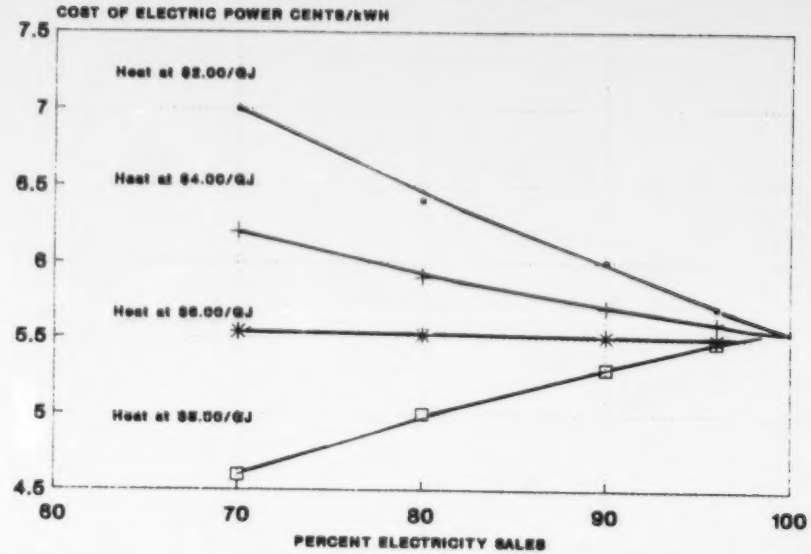
FIGURE 14



OPTION A
VARIABLE -CAPACITY FACTOR

CARIBOO WOODWASTE STUDY

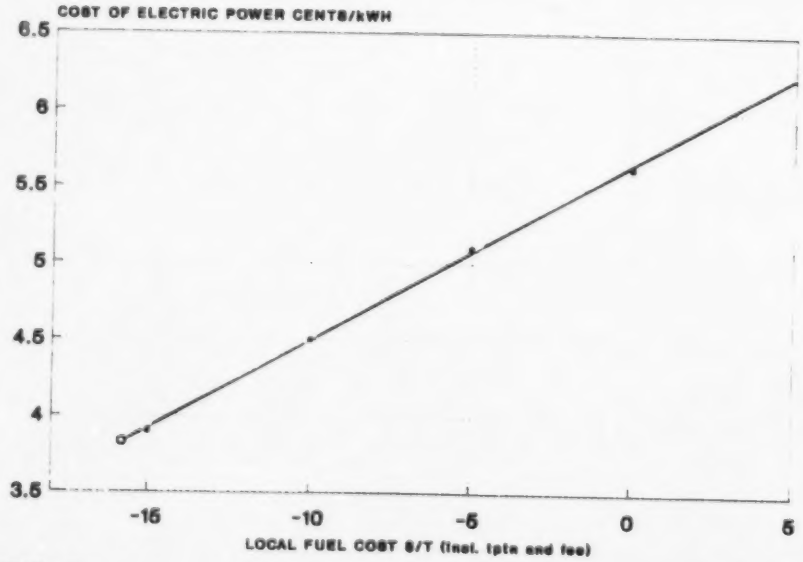
FIGURE 15



OPTION A
VARIABLE -ELECTRIC ENERGY SALES

CARIBOO WOODWASTE STUDY

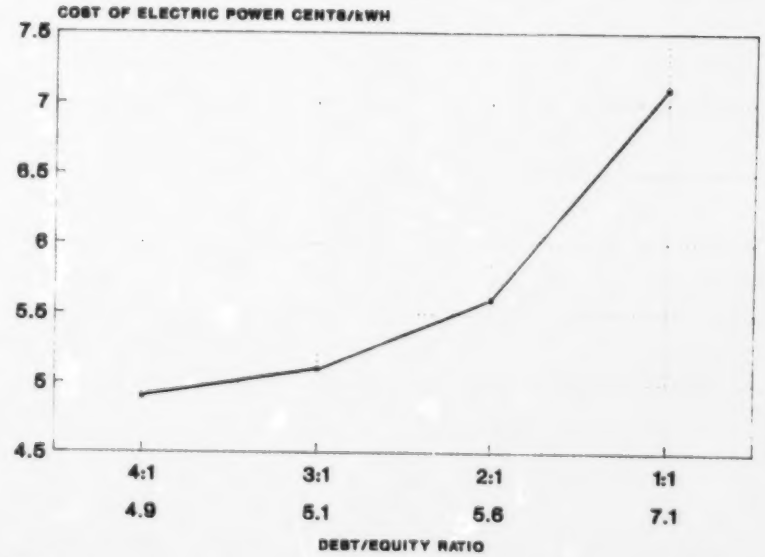
FIGURE 16



OPTION A
VARIABLE -FUEL COST, LOCAL

CARIBOO WOODWASTE STUDY

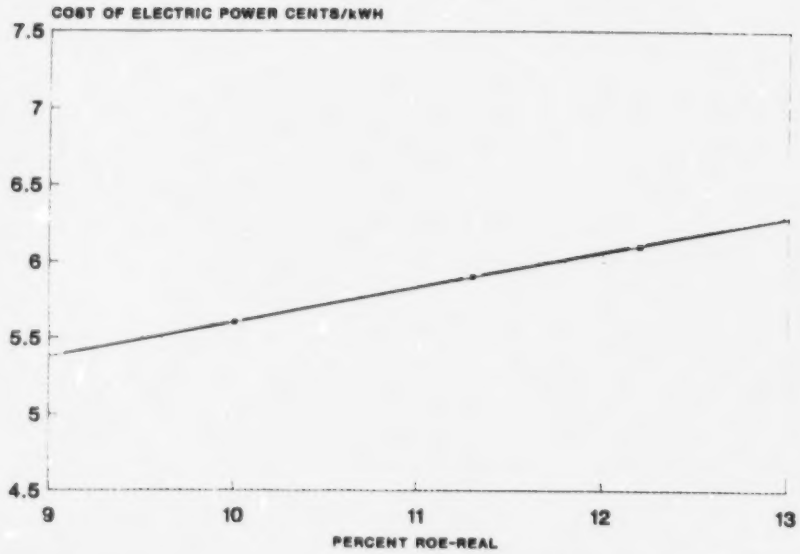
FIGURE 17



OPTION A
VARIABLE -DEBT/EQUITY RATIO

CARIBOO WOODWASTE STUDY

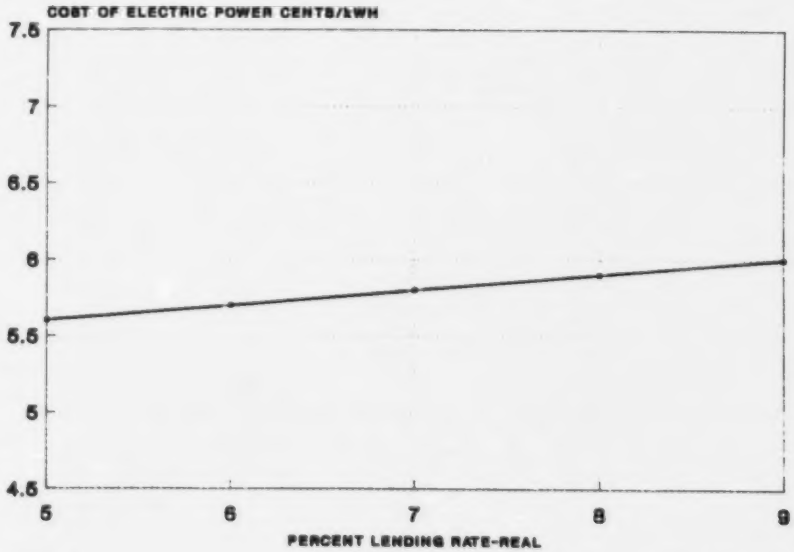
FIGURE 18



OPTION A
VARIABLE -RETURN ON EQUITY

CARIBOO WOODWASTE STUDY

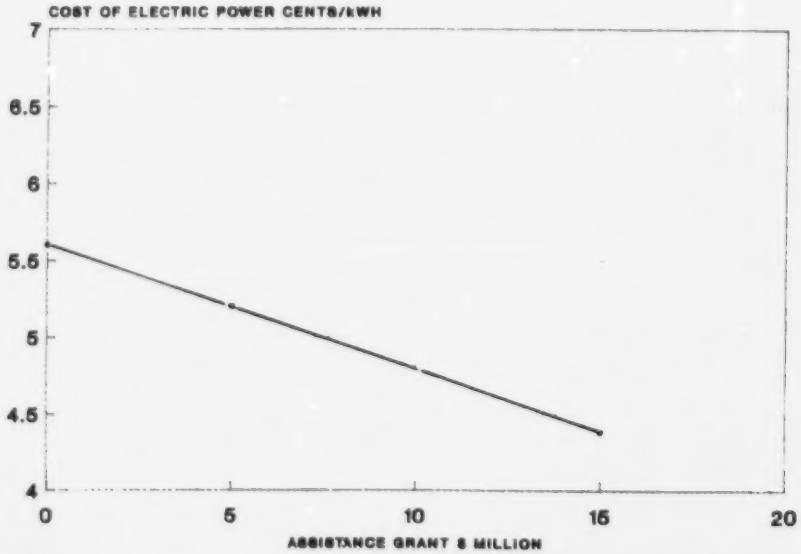
FIGURE 19



OPTION A
VARIABLE -LENDING RATE

CARIBOO WOODWASTE STUDY

FIGURE 20



OPTION A
VARIABLE -ASSISTANCE GRANT

CARIBOO WOODWASTE STUDY

2. Electricity versus Heating Relationship - at current prices ($2.50/GJ) for natural gas heat from a thermal plant cannot compete with natural gas for lumber drying purposes. Where process steam is required the value of the steam should reach approximately $6.00/GJ. At a $6.00/GJ price the value of steam as either electricity or heat is about equal. In other words the plant profitability would be unchanged by the volume of energy going to each sales area.

3. Capital Cost Increase - a 20 percent increase in capital cost forces the required power price up by about 40 percent. Prospective developers would likely undertake a further level of engineering design before price negotiations.

4. Debt/Equity Ratio - if lenders would be prepared to view the project as a traditional utility and provide 4:1 debt financing the power rates could be reduced to 4.9¢/kWh and 4.6¢/kWh for the Base Case and Option A respectively.

5. Return on Equity (ROE) - shareholders wanting a 12 percent real return on investment would require a power price premium of about 0.4¢/kWh or about 7 percent more than at an ROE of 10 percent.

6. Fuel Costs/Sources - provided not more than 20 percent of the woodwaste has to be imported from the immediate area around Williams Lake the effect of adding $5/tonne to the fuel costs increases power costs by only 2 or 3 percent. However, longer hauls from 100 Mile House or Quesnel increase the hauling costs to upwards of $8 to $10/T resulting in power cost increases of 6 percent.

The variable "Fuel Cost (local)" on Tables 23 and 24 has been used to display the approximate costs "to dispose of woodwaste" assuming the B.C. Hydro target of 3.8¢/kWh is to be achieved. The charge for woodwaste disposal at the Base Case plant would have to be approximately $19.00/T. Option A requires $15.00/T which reflects the fact the thermal plant does not bear the transportation cost from the mills.

DEVELOPMENT STRATEGY

General

The multi-objective nature of this study into the use of woodwaste as a co-generation thermal fuel must address the needs of a number of groups. In general, if projects of this type were generally viable on their own, entrepreneurs and investors would have actively pursued construction.

As the study has shown, a gap exists between what B.C. Hydro, the only probable customer, will normally pay and the cost of generation. Unless the project is publicly funded and built, private investors must be attracted to the project. Three principal investors'/developers' concerns will exist.

1. The adequacy of projected returns on investment.

2. The ability to secure long-term fuel supply and power/heat contracts.

3. The extent to which the project is viewed by the community and regulatory authorities as having sufficient merits to proceed without protracted negotiations.

These three aspects have been addressed within this section on development strategy.

Government Programs and Policies

In general, there are no specific programs which offer direct assistance in the feasibility, design construction or start-up phase of a co-generation thermal plant fueled with woodwaste. Specific policies or programs do exist to assist the operating phase.

Tax policy, for example, is helpful. The accelerated capital cost allowance benefits of Class 34 of the Income Tax Regulations permit a 50 percent capital cost allowance for the power portions of capital equipment. This benefit is valuable, but less so for a single project company with only long-term profitability. The tax benefit would have higher value to a larger company likely to incur unusually high profits in the early years of the plant's operation.

Federal government legislation also provides for rebates to the provincial government of federal income tax payable on electric utility income. The Province of Alberta, which has several private electric utilities passes on these rebates to the utilities. Legislation to do the same does not exist in British Columbia. Legislation to this effect in the province would be helpful in promoting the private development of electric power.

Special funding may be possible for larger private sector projects, which fall under the scope of Western Diversification Office (WDO) or a proposed federal-provincial market entry assistance program. Sandwell has assumed no grant is received. Other funding may be available directly from WDO; a formal application requesting consideration of this project has been submitted by the consultants for evaluation purposes. B.C. Hydro's policy on private power purchase also refers to possible grants for special projects.

Alternative Financial Structures

The project economics has been evaluated on a conventional debt equity structure. An alternative financing approach would be the use of preferred shares.

If preferred shares were issued, they might be taken and held by one or several levels of government for redemption in due course. The preferred shares would likely lower the calculated power cost because the preferred share component would be considered low cost debt by common share equity investors. Lenders consider preferred shares as equity which therefore reduces the lender's risk.

A version of this alternative structure is shown in Table 26.

Table 26 - Alternative Financial Structure - Preferred Shares

Item	Composition (%)	Rate of Return (% real)
Long-term Debt	50	5 (before tax)
Preferred Stock	25	4 (after tax)
Common Stock	25	10 (after tax)

A variety of debt and equity proporations is possible within this alternative depending on government project developer's and investor's expectations and requirements.

Within the topic of alternative financing there are a number of possible scenarios for packaging the necessary combination of debt and equity. There is also some prospect that Federal/Provincial incentive programs could provide funds to reduce capital costs. B.C. Hydro, through the IPP program mention grants for some types of projects. Even more alternatives arise if electric power production developers assemble a financing package with wood product developers to effectively optimize the value of the woodwaste available in the local region.

Recommended Development Plan

This report has set out the requirements for successful operation of a dedicated 60MW thermal power plant at Williams Lake. The developers require a plant which is designed, constructed and operated in accordance with the B.C. Hydro's system requirements. The developer, to ensure adequate ROE, requires both long term fuel supply and power sales contracts. Finally, the developer will require a purchase price from B.C. hydro which reflects the higher costs of thermal power and the social-environmental benefits of the project.

Enquiries, by potential developers, should be encouraged and provided with organized and expeditious assistance so that good proposals for a relatively complex project are brought forward.

A lead agency or committee should be established by the various interest groups associated with the project. Representation should be from the City, the mill owners and the Provincial Government. The purpose of the committee or agency would be to serve as a clearing house for issues which cross over several jurisdictions or which are unique and require judgement as to how to resolve the issue.

This lead group should operate in such a manner that the project developer finds reliable assistance and guidance especially in areas that are community related. Ideally, a chairman for the group would be available on a regular basis to meet with the project developer(s). The chairman should have a secretary who could handle enquiries in the chairman's absence.

The development plan should also include some public information program directed at Canadian and U.S. companies that are in the utilities business. The program should comprise a short brochure mailed to a wide variety of potential developers.

The brochure should summarize the woodwaste quantities and mix, the general size of a thermal power facility, the cogeneration opportunities and local contacts for further information.

Selected companies, possibly those who have taken out B.C. Hydro IPP documents, should be sent both a brochure and a copy of this report. A covering letter should invite the companies' consideration of a project at Williams Lake and offer more informal insight into the opportunity, and the nature of potential assistance from the community, Provincial and possibly Federal Governments.

The public information program should be coordinated by the lead agency or committees.

APPENDIX 1

GLOSSARY OF TERMS

REPORT X7801/1
CARIBOO WOODWASTE STUDY

MINISTER OF STATE
CARIBOO DEVELOPMENT REGION
VICTORIA BRITISH COLUMBIA

DATE 9 MARCH 1989

APPENDIX 1 - GLOSSARY OF TERMS AND ABBREVIATIONS

SI UNITS

Term	Abbreviation
amperes	A
amperehour	Ah
annum (see also year)	a
bone dry tonne	BDT
centimetre	cm
cubic centimetre	cm^3
cubic metre	m^3
cycles per second (per Hertz)	Hz
days	d
decibel	dB
decibel (A scale)	dB(A)
degree Celsius (Centigrade)	°C
direct current	DC
farad	F
gigajoule (joules x 10^9)	GJ
gigawatt	GW
gigawatthour	GWh
gram	g
gram per litre	g/L
gram per square centimetre	g/cm^2
hectare	ha
hertz	Hz
hour	h
joule	J
kelvin	K
kiloampere	kA
kilogram	kg
kilogram-metre	kgm
kilometre	km
kilonewton	kN
kilonewton per square metre	kN/m^2
kilopascal	kPa
kilotonne	kt
kilovolt	kV
kilovoltampere	kVA
kilovoltampere reactive	kVAr

SI UNITS (cont'd)

Term	Abbreviation
kilowatt	kW
kilowatthour	kWh
litre	L
megaohm	Mohm
megapascal	MPa
megavoltampere	MVA
megavoltampere reactive	MVAr
megawatt	MW
megawatthour	MWh
metre	m
metre per hour	m/h
metre per minute	m/min
metre per second	m/s
metre water gauge	mwg
microgram per cubic metre	$\mu g/m^3$
milliamp	mA
millimetre	mm
millimetres of mercury	mm Hg
minute	min
newton	N
ohm	ohm
pascal	Pa
second	s
square centimetre	cm^2
square metre	m^2
tonne	T
volt	V
voltampere	VA
voltampere reactive	VAr
watt	W
watthour	Wh
year	a

Non Metric Terms and Units

Term	Abbreviations
absolute (as used in absolute pressure and temperature)	abs
alternating current	AC
annual average rating	AAR
annum (see also year)	a
annual allowable cut	AAC
average annual capacity factor	AACF
barrel	bbl
bone dry	BD
bone dry unit	BDU (2,400 lb)
British thermal unit	Btu
British thermal unit per cubic foot	Btu/ft^3
British thermal unit per gallon	Btu/gal
British thermal unit per pound	Btu/lb
Canadian	Can.
cost, insurance, freight	CIF
cubic foot	ft^3
cubic foot per minute	cfm
cubic foot per second	ft^3/s
day	d
degree	deg (or °)
degree Fahrenheit	°F
drawing	dwg
each	ea
efficiency	eff
elevation	elev
etcetera	etc.
example	e.g.
figure	fig.
foot	ft
foot per minute	fpm
foot per second	fps
forced draft	FD
free on board	FOB
gallon (US)	gal, G
gallon per annum	G/a
gallon per day	G/d
gallon per hour	G/h
gallon per minute	GPM
gallon per second	GPS
gauge (as used in "gauge pressure")	gauge
giga British thermal units (Btu x 10^9)	GBtu

Term	Abbreviation
hour	h
high rupturing capacity	HRC
hydrogen ion concentration	pH
Imperial	Imp
inch	in.
independant power producer	IPP
induced draft	ID
load factor	LF
manhour	mh
maximum	max
maximum continuous rating	MCR
million British thermal unit	MBtu
million gallon per annum	MG/a
minimum	min
minute	min
months	mo
number(s)	no.
parts per million	ppm
per	P,p/ (depending upon particular usage)
percent	%
pound (avoirdupois)	lb
pound per square inch	psi
pound per square inch absolute	psia
pound per square inch gauge	psig
pound per square foot	psf
return on equity	ROE
request for proposal	RFP
revolution per minute	rpm
root mean square	rms
second	s
square feet	sq ft
square inch	sq in.
standard dry cubic foot	SDCF
	SPF
temperature	temp
that is	i.e.
thousand barrel	kbbl
thousand British thermal unit	kB
thousand board feet	kBF
thousand cubic feet	kCF
thousand gallon per day	kG/d
thousand gallon per minute	kGPM
ton (2,000 lb)	T
totally enclosed fan cooled	TEFC

United States	US
volumetric unit (200 ft^3)	VMU

Term	Abbreviation
water gauge (as in inches water gauge)	wg
week	wk
weight	wt
yard	yd
year (see also annum)	a

APPENDIX 2

OPERATING COST ESTIMATES

REPORT X7801/1
CARIBOO WOODWASTE STUDY

MINISTER OF STATE
CARIBOO DEVELOPMENT REGION
VICTORIA BRITISH COLUMBIA

DATE 9 MARCH 1989

APPENDIX 2 - OPERATING COST ESTIMATES

Table 2-1 - Summary of Annual Maximum Operating Costs
Assumes 100 percent load factor ($000)

Item	Base Case		Option A
	*Alt 1	**Alt 2	
Fuel Wood Waste	1,315	1,737	432
Fuel Natural Gas (alternate)	0	0	0
Other Materials	1,400	1,400	1,400
Ash Disposal	309	309	309
Make-up and Blowdown	450	450	450
Salaries and Wages	2,129	2,130	2,130
Administration and Overhead	1,750	1,750	1,750
General Plant Overhead	Incl.	Incl.	Incl.
Supervision Expense	Incl.	Incl.	Incl.
Contingency	367	389	377
Total	7,720	8,165	6,848

* assumes conveyors for 60% of local fuel and trucks for 40%.
** assumes trucks only for all local fuel delivery.

Table 2-2 - Wood Waste Fuel Costs

Item	$/m³	Fuel Volume m³/A	Amount ($000) Alt 1	Alt 2	Option A
Trucking					
Labour	0.19	2,020,000	153	384	0
Fuel	0.10		81	202	0
Tires	0.02		16	40	0
Servicing and Maintenance	0.05		40	101	0
Insurance and Licenses	0.02		16	40	0
Depreciation	0.08		65	162	0
Return on Investment	0.07		57	141	0
Total			428	1,070	0
Conveying to Mill					
Labour	0.05		61	NA	NA
Servicing and Maintenance	0.05		61	NA	NA
Depreciation			90	NA	NA
Power Cost			50	NA	NA
Total			262	0	0
Conveying at Mill					
Labour	0.05		81	101	101
Servicing and Maintenance	0.05		81	101	101
Depreciation			Incl.	Incl.	Incl.
Power Cost			Incl.	Incl.	Incl.
Total			162	202	202
Hogging Costs at Facility or Mill					
Labour	0.09		182	182	91
Materials	0.03		60	60	30
Electric Power	0.05		101	101	50
Capital Recovery	0.06		121	121	61
Total			464	464	232
Overall Total Wood Waste			1,310	1,736	432

Table 2-3 - Salaries and Wages - 60 MW Plant

Item Position	Amount $ 000s Rate/M	Number	Annual
Station Manager	5800	1	69.6
Clerk	2000	1	24.0
Shift Superintendant	5000	2	120.0
Steam Control Engineer (Sen)	4500	4	216.0
Steam Control Engineer (Jun)	3500	4	168.0
Fuel Equipment Operator	3200	8	307.2
Auxiliary Plant Operator	3000	5	180.0
Heavy Machinery Mechanics	3500	2	84.0
Pipefitter/Welder	3500	1	42.0
Control/Electrical Techs	4000	2	96.0
Chemist	4900	1	58.8
Storeman	3000	1	36.0
Maintenance Helper/Driver	2800	2	67.2
Payroll Additives @ 45% of Direct			660.9
TOTAL		34	2,129.7

Table 2-4 - Ash Disposal Cost
Transportation

Item	Amount $000s
Labour	44.7
Fuel	15.0
Tires	1.8
Servicing and Maintenance	13.4
Insurance and Licences	17.8
Depreciation	12.4
Overhead	18.6
TOTAL	109.2
Disposal Costs	
Disposal Fees	200.0
Total Ash Costs	309.2

Table 2-5 - Make Up and Blowdown Water

Item	Amount $000s
Makeup Water	100.0
Blowdown to Sewage	50.0
Water Treatment Plant Consumables	300.0
TOTAL	450.0

Table 2-6 - Other Materials

Item	Amount $000s
Operating Supplies	600.0
Maintenance Materials	800.0

APPENDIX 3

CAPITAL COST ESTIMATES

REPORT X7801/1
CARIBOO WOODWASTE STUDY

MINISTER OF STATE
CARIBOO DEVELOPMENT REGION
VICTORIA BRITISH COLUMBIA

DATE 9 MARCH 1989

APPENDIX 3 - CAPITAL COST ESTIMATE

BASECASE - 60 MW PLANT
INCLUDES COST OF MILL CONVEYORS

STRUCTURES

ACCT. NO.	SITE	Amount in $000 MATERIAL	LABOUR	TOTAL
111.00	Site*	2,310.0	347.8	2,657.8
121.00	Transportation, Garage	INCLUDED IN 211		
122.00	Transportation, Roads	109.2	103.4	212.6
123.00	Transportation, Railroads	.0	.0	.0
131.00	Storm Sewers	10.1	13.2	23.2
132.00	Domestic Effluent Disposal	10.1	9.4	19.5
133.00	Process Effluent Disposal	13.4	15.0	28.5
141.00	Fire Protection	84.0	169.2	253.2
211.00	Offices and Laboratories	562.8	517.0	1,079.8
221.00	Plant Stores	INCLUDED IN 211		
231.00	Maintenance Shop	INCLUDED IN 211		
261.00	Fuel Storage and Handling	2,173.0	693.0	2,866.0
271.00	Water Supply and Distribution	336.0	488.8	824.8
281.00	Steam Supply and Distribution	4,451.9	3,150.0	7,601.9
291.00	Power Supply and Distribution	2,185.2	1,902.6	4,087.8
	Dust Collection Plant	INCLUDED IN 281		
Total Structures		12,245.8	7,409.3	19,655.1

EQUIPMENT

121.00	Transportation, Garage	403.2	18.8	422.0
122.00	Transportation, Roads			.0
123.00	Transportation, Railroads			.0
131.00	Storm Sewers			.0
132.00	Domestic Effluent Disposal			.0
133.00	Process Effluent Disposal	50.4	37.6	88.0
141.00	Fire Protection			.0
211.00	Offices and Laboratories	584.8	117.0	701.8
211.00	Plant Stores	1,251.6	.0	1,251.6
231.00	Maintenance Shop	151.2	75.2	226.4
261.00	Fuel Storage and Handling	9,618.0	1,952.0	11,570.0
271.00	Water Supply and Distribution	144.7	178.6	323.3
281.00	Steam Supply and Distribution	21,279.2	14,214.0	35,963.2
291.00	Power Supply and Distribution	19,380.1	2,427.8	21,807.9
TOTAL EQUIPMENT		52,933.2	18,950.9	71,884.2
TOTAL DIRECT COST				91,539.3

* site costs and site developments.

Total Direct Cost (Previous Page)		**91,539.3**
Heat Distribution (Co-generation)		1,600.0
Owners Construction Overhead		2,260.0
Engineering		9,000.0
Contingencies		9,500.0
B.C. Utility Tie		1,240.0
TOTAL PLANT CAPITAL		115,539.3
Pre-operating Expenses		4,029.9
TOTAL CAPITAL COST (Base Case)		119,169.2
Less:	Hog Fuel Conveyors	5,669.0
Less:	Pre-Operating Expense (Adj)	198.4
TOTAL CAPITAL COST (Option A)		113,301.8

APPENDIX 4

HEAT QUANTITIES AND SELLING PRICES

REPORT X7801/1
CARIBOO WOODWASTE STUDY

MINISTER OF STATE
CARIBOO DEVELOPMENT REGION
VICTORIA BRITISH COLUMBIA

DATE 9 MARCH 1989

APPENDIX 4 - HEAT QUANTITIES AND SELLING PRICES

For purposes of preparing financial analyses of the project, it is necessary to estimate the revenues for heat energy likely to be sold. For comparison, estimates of electric power pricing are presented in Appendix 9 "B.C. Hydro and Markets". An estimate of prices for kiln heat sold to sawmills in William Lake is presented in the following paragraphs. In all cases the heat referred to is high-temperature heat in either steam or liquid form and at temperatures in excess of 180°C.

Heat to Sawmills

It is assumed that heat from extraction steam from the plant would be supplied to private sawmills as a replacement for kiln heat generated from other sources, such as natural gas. As a first approximation, therefore, heat may be equated to the potential savings in natural gas purchases on an equivalent energy basis, excluding any adjustment for kiln-conversion costs or heat transfer losses. Natural gas supplied to dry-kilns in the Williams Lake area would be sold under the Schedule 5 "Large Firm Service-Industrial" of Inland Natural Gas Company.

At present mills at Williams Lake have a group purchase agreement to buy gas and pay to Inland the transmission tariffs only. Gas purchased under this arrangement presently costs about $2.00 to $2.75 per GJ delivered to Williams Lake. Contracts may last for several years but do not offer long term price security.

Natural gas from Inland is currently priced under Schedule 5 and is summarized as follows:

Monthly Rate - Quotes from Inland Natural Gas - Schedule 5

Rate 5.1: Applicable to Buyers with forecasted consumption for the ensuing calendar year of a quantity of gas less than 96,000 gigajoules.

Basic Charge			$500.00 per month
First	500 gigajoules	@	$4.324 per gigajoule
Excess Over	500 gigajoules	@	$3.174 per gigajoule

Rate 5.2: Applicable to Buyers with forecasted consumption for the ensuring calendar year of a quantity of gas equal to or in excess of 96,000 gigajoules, but less than 360,000 gigajoules.

Basic Charge			$500.00 per month
First	500 gigajoules	@	$4.059 per gigajoule
Excess over	500 gigajoules	@	$2.919 per gigajoule

Rate 5.3: Applicable to Buyers with forecasted consumption for the ensuing calendar year of a quantity of gas equal to or in excess of 360,000 gigajoules.

Basic Charge			$500.00 per month
First	500 gigajoules	@	$3.832 per gigajoule
Excess Over	500 gigajoules	@	$2.692 per gigajoule

Dry-kiln operations normally consume sufficient gas per month that the effective rate under Schedule 5 is about $3.00/GJ while direct purchase from gas producers presently costs about $1.50/GJ plus about $1.00/GJ for transmission. Based on current costs, heat energy from the plant would be valued at approx. $4.50 to $5.00/GJ. On a long term basis a price of $4.50/GJ should be competitive.

The long term potential for heat sales is significant if appropriate new projects locate near the proposed plant. The mills adjacent to the plant each consume an estimated 200,000 GJ/a. This amount presents about 3 percent of the plant steam capacity. A proposed Williams Lake particle board plant would consume about 1,300,000 GJ/a or about 20 percent of the plant capacity. The value of a cogeneration facility to the particle board plant should be greater than the equivalent heating value due to the avoided cost of a dedicated steam plant for the particule board plants' needs.

Prices for natural gas are increasing over the long term. Inland Natural Gas forecasts that the prices to small industrial customers will escalate at between 4.5 to 6 percent per year to 2000. This rate is within expected inflation. Large industrial customers may expect a 5.5 to 7.5 percent increase which suggests real increases. Heat energy from the plant would be progressively a more competitive alternative.

As stated previously, the value of heat energy to a local user such as a mill or other process plant should be calculated based upon the competitive alternative. High-temperature heat sales to adjacent mills will likely be gradual as existing heating equipment must be replaced. Pricing will have to take into account any differences in conversion costs. New, high-volume, heat sales should be vigorously pursued because this heat should command higher prices than conversion sales or electric power sales.

Low temperature heat is obtained from the power plant condenser cooling water. It has no alternative value so that its cost is no more than the pipes and pumps necessary to circulate the water to building or greenhouse heat transfer equipment.

APPENDIX 5

FINANCIAL PROJECTIONS - DATA SHEETS

PROJECTED STATEMENT OF INCOME
WILLIAMS LAKE THERMAL - BASE CASE

Calendar Year	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2012	2017	2022
Project Year	-3	-2	-1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	20	25	30
	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----
OPERATING ITEMS		10.09%		CAPACITY FACTOR		85	Percent														
		10.20%		FIXED ENERGY RATE		45	$/Mwh		FIXED HEATING RATE			4	$/GJ	FUEL COST INCREMENT (LOCAL)			1	$/T			
CAPACITY/ENERGY CAPABILITY				VAR. ENERGY RATE		15	$/Mwh		ENERGY TO HEATING			4	%	FUEL COST (REGIONAL)			10	$/T			
Capacity [Mw]	0	0	0																		
Energy [Mwh]	0	0	0	464,778	464,778	464,778	464,778	464,778	464,778	464,778	464,778	464,778	464,778	464,778	464,778	464,778	464,778	464,778	464,778	464,778	464,778
Heat	0	0	0																		
PRODUCTION VOLUMES - SOLD																					
Fixed Energy [Mwh]	0	0	0	223,093	379,259	379,259	379,259	379,259	379,259	379,259	379,259	379,259	379,259	379,259	379,259	379,259	379,259	379,259	379,259	379,259	379,259
Fixed Capacity	0	0	0																		
Variable Energy [Mwh]	0	0	0	223,093	379,259	379,259	379,259	379,259	379,259	379,259	379,259	379,259	379,259	379,259	379,259	379,259	379,259	379,259	379,259	379,259	379,259
Fixed Heat [GJ]	0	0	0	88,261	150,044	150,044	150,044	150,044	150,044	150,044	150,044	150,044	150,044	150,044	150,044	150,044	150,044	150,044	150,044	150,044	150,044
Variable Heat	0	0	0																		
UNIT PRICES																					
Fixed Energy Rate [$/Mwh]	0	0	0	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
Fixed Capacity Rate	0	0	0																		
Variable Energy Rate [$/Mwh]	0	0	0	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Fixed Heating Rate [$/GJ]	0	0	0	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Variable Heating Rate	0	0	0																		
Fuel Wood Waste, Local [$/Tonne]	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Fuel Wood Waste, Regional [$/Tonne]	0	0	0	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
OPERATING REVENUES																					
Fixed Energy Sales	0	0	0	10,039	17,067	17,067	17,067	17,067	17,067	17,067	17,067	17,067	17,067	17,067	17,067	17,067	17,067	17,067	17,067	17,067	17,067
Fixed Capacity Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Variable Energy Sales	0	0	0	3,346	5,689	5,689	5,689	5,689	5,689	5,689	5,689	5,689	5,689	5,689	5,689	5,689	5,689	5,689	5,689	5,689	5,689
Fixed Heating Sales	0	0	0	353	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
Variable Heating Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Products	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL OPERATING REVENUES	0	0	0	13,739	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356

Fixed Capacity Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Variable Energy Sales	0	0	0	3,346	5,689	5,689	5,689	5,689	5,689	5,689	5,689	5,689	5,689	5,689	5,689	5,689	5,689	5,689	5,689	5,689	5,689	5,689
Fixed Heating Sales	0	0	0	353	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
Variable Heating Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Products	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL OPERATING REVENUES	0	0	0	13,739	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356
COST OF GOODS SOLD																						
OPERATING EXPENSES	FUEL SOURCE PERCENTAGE LOCAL				100	PERCENT																
Fuel, Wood Waste (Local)	0	0	0	254	432	432	432	432	432	432	432	432	432	432	432	432	432	432	432	432	432	432
Fuel, Wood Waste (Regional)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Salaries and Labour	0	0	0	2,130	2,130	2,130	2,130	2,130	2,130	2,130	2,130	2,130	2,130	2,130	2,130	2,130	2,130	2,130	2,130	2,130	2,130	2,130
Ash Disposal	0	0	0	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91
Administration	0	0	0	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Consumables	0	0	0	288	490	490	490	490	490	490	490	490	490	490	490	490	490	490	490	490	490	490
Water & Treatment	0	0	0	216	367	367	367	367	367	367	367	367	367	367	367	367	367	367	367	367	367	367
Maintenance, Routine	0	0	0	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Contingency	0	0	0	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
TOTAL OPERATING EXPENSES	0	0	0	3,779	4,310	4,310	4,310	4,310	4,310	4,310	4,310	4,310	4,310	4,310	4,310	4,310	4,310	4,310	4,310	4,310	4,310	4,310
GROSS PROFIT	0	0	0	9,960	19,046	19,046	19,046	19,046	19,046	19,046	19,046	19,046	19,046	19,046	19,046	19,046	19,046	19,046	19,046	19,046	19,046	19,046
OTHER OPERATING EXPENSES																						
Property Taxes and Insurance				1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550
Depreciation [Book]*	0	0	0	4,062	3,947	3,836	3,729	3,625	3,524	3,427	3,333	3,242	3,154	3,069	2,987	2,908	2,831	2,757	2,430	2,144	1,903	
Capitalized Expense	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL OTHER OPERATING EXPENSES	0	0	0	5,612	5,497	5,386	5,279	5,175	5,074	4,977	4,883	4,792	4,704	4,619	4,537	4,458	4,381	4,307	3,980	3,694	3,453	
OPERATING PROFIT	0	0	0	4,347	13,548	13,660	13,767	13,871	13,972	14,069	14,163	14,254	14,342	14,427	14,509	14,588	14,665	14,739	15,065	15,352	15,593	
NON-OPERATING INCOME & EXPENSES																						
Amortization Loan Expense	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Interest Loan #1 Amortized Loan	397	397	397	379	359	339	318	296	272	247	221	194	166	136	104	71	36	0	0	0	0	
Interest Loan #2 Amortized Loan	0	1,589	1,589	1,515	1,438	1,357	1,272	1,182	1,088	989	886	777	663	543	417	285	146	0	0	0	0	
Interest Loan #3 Amortized Loan	0	0	1,986	1,894	1,797	1,696	1,589	1,478	1,360	1,237	1,107	971	828	679	521	356	182	0	0	0	0	
Capitalized Interest	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
TOTAL INTEREST EXPENSES	397	1,986	3,972	3,788	3,595	3,392	3,179	2,955	2,720	2,473	2,214	1,942	1,657	1,357	1,042	712	364	0	0	0	0	
INCOME BEFORE TAXES	(397)	(1,986)	(3,972)	559	9,954	10,268	10,588	10,916	11,252	11,596	11,949	12,311	12,685	13,070	13,467	13,877	14,300	14,739	15,065	15,352	15,593	
INCOME TAXES																						
Current FIT	0	0	0	0	0	0	0	0	0	0	402	6,424	6,637	6,825	7,004	7,182	7,362	7,547	7,608	7,654	7,690	
Deferred FIT	0	0	0	260	4,623	4,769	4,918	5,071	5,226	5,386	5,148	(705)	(745)	(755)	(749)	(736)	(719)	(701)	(611)	(523)	(447)	
TOTAL FIT	0	0	0	260	4,623	4,769	4,918	5,071	5,226	5,386	5,550	5,719	5,892	6,071	6,255	6,446	6,643	6,846	6,998	7,131	7,243	
NET INCOME	(397)	(1,986)	(3,972)	299	5,330	5,498	5,670	5,846	6,025	6,209	6,398	6,593	6,793	6,999	7,211	7,431	7,658	7,893	8,068	8,221	8,350	

BASE CASE
PROJECTED STATEMENT OF INCOME TABLE 5-1

PROJECTED BALANCE SHEET Calendar Year	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2012	2017	2022
Project Year	-3	-2	-1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	20	25	30
WILLIAMS LAKE - BASE CASE																					
ASSETS																					
Cash	(397)	(2,383)	(6,356)	(6,107)	2,581	12,026	21,481	30,946	40,423	49,912	59,044	62,629	65,536	68,268	70,835	73,241	75,482	77,557	124,112	170,411	216,511
Temporary Investments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Accounts Receivable	0	0	0	1,129	1,920	1,920	1,920	1,920	1,920	1,920	1,920	1,920	1,920	1,920	1,920	1,920	1,920	1,920	1,920	1,920	1,920
Other Current Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL CURRENT ASSETS	(397)	(2,383)	(6,356)	(4,978)	4,501	13,945	23,400	32,866	42,343	51,831	60,963	64,548	67,456	70,188	72,755	75,160	77,402	79,476	126,032	172,331	218,430
Cons. Work in Progress	11,917	59,585	119,169	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Prop. Plant & Equipment*	0	0	0	119,169	119,769	120,369	120,969	121,569	122,169	122,769	123,369	123,969	124,569	125,169	125,769	126,369	126,969	127,569	130,569	133,569	136,569
- Accumulated Depreciation [Book]*	0	0	0	4,062	8,010	11,846	15,574	19,199	22,723	26,150	29,483	32,724	35,879	38,948	41,935	44,842	47,673	50,430	63,193	74,466	84,445
NET PROPERTY, PLANT & EQUIPMENT	11,917	59,585	119,169	115,107	111,759	108,523	105,395	102,370	99,446	96,619	93,887	91,245	88,691	86,221	83,834	81,527	79,296	77,139	67,377	59,103	52,124
Unamortized Debt Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL ASSETS	11,520	57,201	112,814	110,129	116,260	122,469	128,795	135,236	141,789	148,451	154,850	155,793	156,147	156,409	156,589	156,687	156,698	156,616	193,408	231,434	270,555
CURRENT LIABILITIES																					
Accounts Payable	0	0	0	311	354	354	354	354	354	354	354	356	354	354	354	354	354	354	354	354	354
Other Payables	0	0	0	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127
Income Tax Payable	0	0	0	0	0	0	0	0	0	0	33	528	546	561	576	590	605	620	625	629	632
TOTAL CURRENT LIABILITIES	0	0	0	438	482	482	482	482	482	482	515	1,010	1,027	1,043	1,057	1,072	1,087	1,102	1,107	1,111	1,114
BANK LOANS																					
Loan #1 Amortized Loan	7,945	7,945	7,945	7,576	7,190	6,784	6,358	5,910	5,440	4,947	4,429	3,885	3,314	2,714	2,084	1,423	729	0	0	0	0
Loan #2 Amortized Loan	0	31,778	31,778	30,306	28,759	27,136	25,431	23,641	21,761	19,788	17,716	15,540	13,255	10,856	8,338	5,693	2,916	0	0	0	0
Loan #3 Amortized Loan	0	0	39,723	37,882	35,949	33,920	31,789	29,551	27,202	24,735	22,145	19,425	16,569	13,570	10,422	7,116	3,645	0	0	0	0
Loan Bond	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOANS	7,945	39,723	79,446	75,764	71,899	67,840	63,577	59,102	54,403	49,470	44,289	38,849	33,138	27,141	20,844	14,232	7,290	0	0	0	0
DEFERRED FIT	0	0	0	260	4,803	9,652	14,571	19,641	24,868	30,254	35,402	34,697	33,952	33,197	32,448	31,712	30,993	30,292	27,069	24,283	21,899
Common Stock	3,972	19,862	39,723	39,723	39,723	39,723	39,723	39,723	39,723	39,723	39,723	39,723	39,723	39,723	39,723	39,723	39,723	39,723	39,723	39,723	39,723
Grant			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Stock Repurchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retained Earnings	(397)	(2,383)	(6,356)	(6,056)	(726)	4,772	10,442	16,288	22,313	28,523	34,921	41,514	48,307	55,305	62,517	69,948	77,606	85,498	125,509	166,317	207,819
TOTAL OWNER'S EQUITY	3,575	17,478	33,367	33,667	38,997	44,495	50,165	56,011	62,036	68,246	74,644	81,237	88,030	95,028	102,240	109,671	117,329	125,221	165,232	206,040	247,542
TOTAL OWNER'S EQUITY & LIABILITIES	11,520	57,201	112,814	110,129	116,260	122,469	128,795	135,236	141,789	148,451	154,850	155,793	156,147	156,409	156,589	156,687	156,698	156,616	193,408	231,434	270,555
RETAINED EARNINGS CALCULATION																					
Retained Earnings (Start of Year)	0	(397)	(2,383)	(6,356)	(6,056)	(726)	4,772	10,442	16,288	22,313	28,523	34,921	41,514	48,307	55,305	62,517	69,948	77,606	117,441	158,096	199,468
Income (Loss) for year	(397)	(1,986)	(3,972)	299	5,330	5,498	5,670	5,846	6,025	6,209	6,398	6,593	6,793	6,999	7,211	7,431	7,658	7,893	8,068	8,221	8,350
Less Dividends Paid	0																				
Retained Earnings (End of Year)	(397)	(2,383)	(6,356)	(6,056)	(726)	4,772	10,442	16,288	22,313	28,523	34,921	41,514	48,307	55,305	62,517	69,948	77,606	85,498	125,509	166,317	207,819

BASE CASE
PROJECTED BALANCE SHEET - TABLE 5-2

CASH FLOW FROM OPERATIONS & EXTERNAL CASH — WILLARD LAKE - BASE CASE	Calendar Year	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2012	2017	2022
	Project Year	-3	-2	-1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	20	25	30
NET INCOME		(397)	(1,986)	(3,972)	299	5,330	5,498	5,670	5,846	6,025	6,209	6,398	6,593	6,793	6,999	7,211	7,431	7,658	7,893	8,068	8,221	8,350
PLUS: Depreciation [Book]		0	0	0	4,062	3,947	3,836	3,729	3,625	3,524	3,427	3,333	3,242	3,154	3,069	2,987	2,908	2,831	2,757	2,430	2,144	1,903
Interest Expense		397	1,986	3,972	3,788	3,595	3,392	3,179	2,955	2,720	2,473	2,214	1,942	1,657	1,357	1,042	712	364	0	0	0	0
Tax Effect of Interest		(185)	(923)	(1,845)	(1,760)	(1,670)	(1,576)	(1,477)	(1,373)	(1,264)	(1,149)	(1,029)	(902)	(770)	(630)	(484)	(331)	(169)	0	0	0	0
Income Tax Accrual		0	0	0	208	4,623	4,769	4,918	5,071	5,226	5,386	5,148	(705)	(745)	(755)	(749)	(736)	(719)	(701)	(611)	(523)	(447)
Amortization Debt Expense		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL ADDITIONS		213	1,064	2,127	6,351	10,496	10,422	10,349	10,278	10,207	10,137	9,667	3,577	3,296	3,041	2,796	2,553	2,307	2,056	1,820	1,621	1,455
LESS: Current FIT		0	0	0	0	0	0	0	0	0	0	402	6,424	6,637	6,825	7,004	7,182	7,362	7,547	7,608	7,654	7,690
Temporary Investment Income		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tax Effects Temporary Investment		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL DEDUCTIONS		0	0	0	0	0	0	0	0	0	0	402	6,424	6,637	6,825	7,004	7,182	7,362	7,547	7,608	7,654	7,690
AFTER TAX FUNDS BEFORE CHANGES IN WORKING CAPITAL		(185)	(923)	(1,845)	6,650	15,026	15,920	16,019	16,123	16,232	16,347	15,664	3,745	3,452	3,215	3,003	2,802	2,603	2,401	2,279	2,188	2,115
PLUS: Increase in Accounts Payable		0	0	0	311	44	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Increase in Other Accounts Payable		0	0	0	127	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Increase in Taxes Payable		0	0	0	0	0	0	0	0	0	0	402	6,022	213	188	179	177	180	185	11	8	7
TOTAL ADDITIONS		0	0	0	438	44	0	0	0	0	0	402	6,022	213	188	179	177	180	185	11	8	7
LESS: Increase in Accounts Receivable		0	0	0	1,129	790	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Increase in Other Current Assets		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL DEDUCTIONS		0	0	0	1,129	790	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CASH FROM OPERATING CYCLE		(185)	(923)	(1,845)	5,959	15,079	15,920	16,019	16,123	16,232	16,347	16,066	9,768	3,665	3,403	3,182	2,979	2,783	2,587	2,290	2,196	2,122
LESS: Fixed Capital Investment		11,917	47,664	59,585	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capitalized Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capitalized Interest		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CASH FROM OPERATIONS BEFORE EXTERNAL FINANCING & INTEREST INCOME & EXPENSES		(12,101)	(48,590)	(61,430)	5,959	15,079	15,920	16,019	16,123	16,232	16,347	16,066	9,768	3,665	3,403	3,182	2,979	2,783	2,587	2,290	2,196	2,122
- Change in Temporary Investment		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
+ Temporary Investment After Tax		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
- Interest Expenses After Tax		213	1,064	2,127	2,029	1,925	1,816	1,702	1,582	1,457	1,325	1,186	1,040	887	727	558	381	195	0	0	0	0
CASH BEFORE EXTERNAL FINANCINGS		(12,314)	(49,654)	(63,557)	3,930	13,154	14,104	14,317	14,541	14,776	15,022	14,880	8,728	2,778	2,676	2,624	2,598	2,588	2,587	2,290	2,196	2,122
- Debt Expenses		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
+ Increase in Debt		7,945	31,778	39,723	(3,682)	(3,866)	(4,059)	(4,262)	(4,475)	(4,699)	(4,934)	(5,181)	(5,440)	(5,712)	(5,997)	(6,297)	(6,612)	(6,942)	(7,290)	0	0	0
+ Stock Sale Proceeds		3,972	15,889	19,862	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
+ Grant				0	-																	
- Dividends & Repurchase		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EQUITY CASH FLOWS		(3,972)	(15,889)	(19,862)	248	9,288	10,045	10,055	10,066	10,077	10,089	9,699	3,288	(2,934)	(3,321)	(3,673)	(4,013)	(4,355)	(4,703)	2,290	2,196	2,122

IRR 20 years ..: 10.09%

IRR 30 years ..: 10.20%

BASE CASE
CASH FLOW FROM OPERATIONS
& EXTERNAL CASH - TABLE 5-3

PROJECTED CASH STATEMENT Calendar Year	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2012	2017	2022
========== Project Year	-1	-2	-1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	20	25	30
WILLIAMS LAKE - BASE CASE	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	---
RECEIPTS																					
Operating Revenues	0	0	0	12,609	22,565	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356
Investments Revenues	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL RECEIPTS	0	0	0	12,609	22,565	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356	23,356
DISBURSEMENTS																					
Operating Expenses	0	0	0	3,468	4,266	4,310	4,310	4,310	4,310	4,310	4,310	4,310	4,310	4,310	4,310	4,310	4,310	4,310	4,310	4,310	4,310
Interest Expenses	397	1,986	3,972	3,788	3,595	3,392	3,179	2,955	2,720	2,473	2,214	1,942	1,657	1,357	1,042	712	364	0	0	0	0
Current FIT	0	0	0	0	0	0	0	0	0	0	369	5,929	6,620	6,810	6,990	7,167	7,347	7,532	7,688	7,653	7,690
Property Taxes and Insurance	0	0	0	1,423	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550
TOTAL DISBURSEMENTS	397	1,986	3,972	8,679	9,411	9,252	9,039	8,815	8,580	8,333	8,443	13,731	14,136	14,027	13,892	13,739	13,571	13,392	13,467	13,513	13,550
CASH FROM OPERATIONS	(397)	(1,986)	(3,972)	3,930	13,154	14,104	14,317	14,541	14,776	15,022	14,913	9,624	9,219	9,329	9,464	9,617	9,784	9,964	9,888	9,842	9,806
BEGINNING CASH BALANCE	0	(397)	(2,383)	(6,356)	(6,107)	2,581	12,026	21,481	30,946	40,423	49,912	59,044	62,629	65,536	68,268	70,835	73,241	75,482	114,824	161,169	207,305
CAPITAL AQUISITION*	11,917	47,668	59,585	0	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
DIVIDENDS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FINANCING PROCEEDS																					
Loan Proceeds	7,945	31,778	39,723	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Loan Repayments	0	0	0	(3,682)	(3,866)	(4,059)	(4,262)	(4,475)	(4,699)	(4,934)	(5,181)	(5,440)	(5,712)	(5,997)	(6,297)	(6,612)	(6,942)	(7,290)	0	0	0
Common Stock	3,972	15,889	19,862	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Grant			0																		
TOTAL FINANCING PROCEEDS	11,917	47,668	59,585	(3,682)	(3,866)	(4,059)	(4,262)	(4,475)	(4,699)	(4,934)	(5,181)	(5,440)	(5,712)	(5,997)	(6,297)	(6,612)	(6,942)	(7,290)	0	0	0
ENDING CASH BALANCE	(397)	(2,383)	(6,356)	(6,107)	2,581	12,026	21,481	30,946	40,423	49,912	59,044	62,629	65,536	68,268	70,835	73,241	75,482	77,557	124,112	170,411	216,511

BASE CASE
PROJECTED CASH STATEMENT - TABLE 5-4

FINANCING

	Calender Year	1990	1991	1992
	Project Year	-3	-2	-1
WILLIAMS LAKE - BASE CASE		----	----	----
LOAN SPECIFICATION		LOAN 1	LOAN 2	LOAN 3
Percent of Capital Costs		10.00%	40.00%	50.00%
Principal Amount		7,945	31,778	39,723
Interest Rate		5.00%	5.00%	5.00%
Term (Years)		15	15	15
EQUITY REQUIRED		3,972	15,889	19,862
ASSISTANCE GRANT				0
TOTAL FUNDS REQUIRED		11,917	47,668	59,585
TOTAL FUNDS		11,917	47,668	59,585

WILLIAMS LAKE THERMAL PLANT - BASE CASE

CAPITAL COST ESTIMATE FOR FINANCING PURPOSES: 119,169

DEBT/EQUITY RATIO 2 TO 1

BASE CASE
FINANCING - TABLE 5-5

AMORTIZATION SCHEDULE FOR LOAN #1

Amount of Loan	$7,945
Payments per Year	1
Term of Loan (Years)	15
Annual Interest Rate	5.00%
Payment Each Period	765

Years	Balance	Principal	Int.
1	7,576	368	397
2	7,190	387	379
3	6,784	406	359
4	6,358	426	339
5	5,910	448	318
6	5,440	470	296
7	4,947	493	272
8	4,429	518	247
9	3,885	544	221
10	3,314	571	194
11	2,714	600	166
12	2,084	630	136
13	1,423	661	104
14	729	694	71
15	0	729	36

AMORTIZATION SCHEDULE FOR LOAN #2

Amount of Loan	$31,778
Payments per Year	1
Term of Loan (Years)	15
Annual Interest Rate	5.00%
Payment Each Period	3,062

Years	Balance	Principal	Int.
1	30,306	1,473	1,589
2	28,759	1,546	1,515
3	27,136	1,624	1,438
4	25,431	1,705	1,357
5	23,641	1,790	1,272
6	21,761	1,880	1,182
7	19,788	1,974	1,088
8	17,716	2,072	989
9	15,540	2,176	886
10	13,255	2,285	777
11	10,856	2,399	663
12	8,338	2,519	543
13	5,693	2,645	417
14	2,916	2,777	285
15	0	2,916	146

AMORTIZATION SCHEDULE FOR LOAN #3

Amount of Loan	$39,723
Payments per Year	1
Term of Loan (Years)	15
Annual Interest Rate	5.00%
Payment Each Period	3,827

Years	Balance	Principal	Int.
1	37,882	1,841	1,986
2	35,949	1,933	1,894
3	33,920	2,030	1,797
4	31,789	2,131	1,696
5	29,551	2,238	1,589
6	27,202	2,349	1,478
7	24,735	2,467	1,360
8	22,145	2,590	1,237
9	19,425	2,720	1,107
10	16,569	2,856	971
11	13,570	2,999	828
12	10,422	3,148	679
13	7,116	3,306	521
14	3,645	3,471	356
15	0	3,645	182

LOAN #1

Years	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Balance	7,576	7,190	6,784	6,358	5,910	5,440	4,947	4,429	3,885	3,314	2,714	2,084	1,423	729	0
Principal	368	387	406	426	448	470	493	518	544	571	600	630	661	694	729
Interest	397	379	359	339	318	296	272	247	221	194	166	136	104	71	36

LOAN #2

Years	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Balance	30,306	28,759	27,136	25,431	23,641	21,761	19,788	17,716	15,540	13,255	10,856	8,338	5,693	2,916	0
Principal	1,473	1,546	1,624	1,705	1,790	1,880	1,974	2,072	2,176	2,285	2,399	2,519	2,645	2,777	2,916
Interest	1,589	1,515	1,438	1,357	1,272	1,182	1,088	989	886	777	663	543	417	285	146

LOAN #3

Years	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Balance	37,882	35,949	33,920	31,789	29,551	27,202	24,735	22,145	19,425	16,569	13,570	10,422	7,116	3,645	0
Principal	1,841	1,933	2,030	2,131	2,238	2,349	2,467	2,590	2,720	2,856	2,999	3,148	3,306	3,471	3,645
Interest	1,986	1,894	1,797	1,696	1,589	1,478	1,360	1,237	1,107	971	828	679	521	356	182

DEFERRED TAX CALCULATION	Calender Year	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2012	2017	2022
==========	Project Year	-3	-2	-1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	20	25	30
WILLIAMS LAKE - BASE CASE		----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----
TAX ACCRUAL CALCULATION																						
Income Before Taxes		(397)	(1,986)	(3,972)	559	9,954	10,260	10,588	10,916	11,252	11,596	11,949	12,311	12,685	13,070	13,467	13,877	14,300	14,739	15,065	15,352	15,593
Tax Rate		46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%
Income Tax Accrual		(185)	(923)	(1,845)	260	4,623	4,769	4,918	5,071	5,226	5,386	5,550	5,719	5,892	6,071	6,255	6,446	6,643	6,846	6,998	7,131	7,243
CURRENT FEDERAL INCOME TAXES CALCULATION																						
Income Before Taxes		(397)	(1,986)	(3,972)	559	9,954	10,260	10,588	10,916	11,252	11,596	11,949	12,311	12,685	13,070	13,467	13,877	14,300	14,739	15,065	15,352	15,593
+ Depreciation [Book]*		0	0	0	4,062	3,947	3,836	3,729	3,625	3,524	3,427	3,333	3,242	3,154	3,069	2,987	2,908	2,831	2,757	2,430	2,144	1,903
Income to Tax [Prior LCF & CCA]		(397)	(1,986)	(3,972)	4,621	13,901	14,104	14,317	14,541	14,776	15,022	15,281	15,553	15,839	16,139	16,454	16,784	17,131	17,496	17,496	17,496	17,496
Loss Carry Forward																						
Opening Balance		0	(397)	(2,383)	(6,356)	(1,734)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
+ Income to Tax [Prior LCF & CCA]		(397)	(1,986)	(3,972)	4,621	13,901	14,104	14,317	14,541	14,776	15,022	15,281	15,553	15,839	16,139	16,454	16,784	17,131	17,496	17,496	17,496	17,496
Balance Carry Forward		(397)	(2,383)	(6,356)	(1,734)	12,167	14,104	14,317	14,541	14,776	15,022	15,281	15,553	15,839	16,139	16,454	16,784	17,131	17,496	17,496	17,496	17,496
Income to Tax [Prior to CCA]		0	0	0	0	12,167	14,104	14,317	14,541	14,776	15,022	15,281	15,553	15,839	16,139	16,454	16,784	17,131	17,496	17,496	17,496	17,496
Capital Cost Allowance Calculation																						
Balance from previous year		0	0	0	0	22,654	45,019	49,071	44,682	35,920	24,817	12,388	0	0	0	0	0	0	0	0	0	0
+ Total Annual CCA [Depr. Tax]*		0	0	0	22,654	34,532	18,155	9,928	5,779	3,673	2,593	2,028	1,723	1,550	1,465	1,375	1,323	1,282	1,248	1,116	1,018	940
Total CCA available		0	0	0	22,654	57,186	63,175	58,999	50,460	39,593	27,411	14,417	1,723	1,550	1,465	1,375	1,323	1,282	1,248	1,116	1,018	940
- Income to Tax [Prior to CCA]		0	0	0	0	12,167	14,104	14,317	14,541	14,776	15,022	15,281	15,553	15,839	16,139	16,454	16,784	17,131	17,496	17,496	17,496	17,496
CCA Used		0	0	0	0	12,167	14,104	14,317	14,541	14,776	15,022	14,417	1,723	1,550	1,465	1,375	1,323	1,282	1,248	1,116	1,018	940
Balance Cumulative CCA		0	0	0	22,654	45,019	49,071	44,682	35,920	24,817	12,388	0	0	0	0	0	0	0	0	0	0	0
Taxable Income		0	0	0	0	0	0	0	0	0	0	865	13,830	14,289	14,694	15,079	15,461	15,849	16,248	16,380	16,478	16,556
Effective Tax Rate		46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%
Current FIT		0	0	0	0	0	0	0	0	0	0	402	6,424	6,637	6,825	7,004	7,182	7,362	7,547	7,608	7,654	7,690
DEFFERED FEDERAL INCOME TAXES CALCULATION																						
Income Tax Accrual		0	0	0	260	4,623	4,769	4,918	5,071	5,226	5,386	5,550	5,719	5,892	6,071	6,255	6,446	6,643	6,846	6,998	7,131	7,243
- Current FIT		0	0	0	0	0	0	0	0	0	0	402	6,424	6,637	6,825	7,004	7,182	7,362	7,547	7,608	7,654	7,690
Deferred FIT		0	0	0	260	4,623	4,769	4,918	5,071	5,226	5,386	5,148	(705)	(745)	(755)	(749)	(736)	(719)	(701)	(611)	(523)	(447)

BASE CASE
DEFERRED TAX CALCULATION - TABLE 5-6

PROJECTED STATEMENT OF INCOME

WILLIAMS LAKE THERMAL - OPTION A

Calendar Year	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2012	2017	2022
Project Year	-3	-2	-1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	20	25	30
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OPERATING ITEMS		9.99%		CAPACITY FACTOR		85	Percent														
		10.11%		FIXED ENERGY RATE		45	$/Mwh		FIXED HEATING RATE			4	$/GJ	FUEL COST INCREMENT (LOCAL)			0	$/T			
CAPACITY/ENERGY CAPABILITY				VAR. ENERGY RATE		11	$/Mwh		ENERGY TO HEATING			4	%	FUEL COST (REGIONAL)			8	$/T			
Capacity [Mw]	0	0	0																		
Energy [Mwh]	0	0	0	469,278	469,278	469,278	469,278	469,278	469,278	469,278	469,278	469,278	469,278	469,278	469,278	469,278	469,278	469,278	469,278	469,278	469,278
Heat	0	0	0																		
PRODUCTION VOLUMES - SOLD																					
Fixed Energy (Mwh)	0	0	0	225,253	382,931	382,931	382,931	382,931	382,931	382,931	382,931	382,931	382,931	382,931	382,931	382,931	382,931	382,931	382,931	382,931	382,931
Fixed Capacity	0	0	0																		
Variable Energy (Mwh)	0	0	0	225,253	382,931	382,931	382,931	382,931	382,931	382,931	382,931	382,931	382,931	382,931	382,931	382,931	382,931	382,931	382,931	382,931	382,931
Fixed Heat (GJ)	0	0	0	89,116	151,497	151,497	151,497	151,497	151,497	151,497	151,497	151,497	151,497	151,497	151,497	151,497	151,497	151,497	151,497	151,497	151,497
Variable Heat	0	0	0																		
UNIT PRICES																					
Fixed Energy Rate [$/Mwh]	0	0	0	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
Fixed Capacity Rate	0	0	0																		
Variable Energy Rate [$/Mwh]	0	0	0	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Fixed Heating Rate ($/GJ)	0	0	0	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Variable Heating Rate	0	0	0																		
Fuel Wood Waste, Local [$/Tonne]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Wood Waste, Regional [$/Tonne]	0	0	0	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
OPERATING REVENUES																					
Fixed Energy Sales	0	0	0	10,136	17,232	17,232	17,232	17,232	17,232	17,232	17,232	17,232	17,232	17,232	17,232	17,232	17,232	17,232	17,232	17,232	17,232
Fixed Capacity Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Variable Energy Sales	0	0	0	2,478	4,212	4,212	4,212	4,212	4,212	4,212	4,212	4,212	4,212	4,212	4,212	4,212	4,212	4,212	4,212	4,212	4,212
Fixed Heating Sales	0	0	0	356	606	606	606	606	606	606	606	606	606	606	606	606	606	606	606	606	606
Variable Heating Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Products	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL OPERATING REVENUES	0	0	0	12,971	22,050	22,050	22,050	22,050	22,050	22,050	22,050	22,050	22,050	22,050	22,050	22,050	22,050	22,050	22,050	22,050	22,050
COST OF GOODS SOLD																					
OPERATING EXPENSES	FUEL SOURCE PERCENTAGE LOCAL				100	PERCENT															
Fuel, Wood Waste (Local)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel, Wood Waste (Regional)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Salaries and Labour	0	0	0	2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039
Ash Disposal	0	0	0	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91
Administration	0	0	0	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Consumables	0	0	0	273	465	465	465	465	465	465	465	465	465	465	465	465	465	465	465	465	465
Water & Treatment	0	0	0	216	367	367	367	367	367	367	367	367	367	367	367	367	367	367	367	367	367
Maintenance, Routine	0	0	0	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Contingency	0	0	0	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
TOTAL OPERATING EXPENSES	0	0	0	3,419	3,762	3,762	3,762	3,762	3,762	3,762	3,762	3,762	3,762	3,762	3,762	3,762	3,762	3,762	3,762	3,762	3,762
GROSS PROFIT	0	0	0	9,551	18,288	18,288	18,288	18,288	18,288	18,288	18,288	18,288	18,288	18,288	18,288	18,288	18,288	18,288	18,288	18,288	18,288
OTHER OPERATING EXPENSES																					
Property Taxes and Insurance				1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550
Depreciation [Book]*	0	0	0	3,889	3,780	3,674	3,572	3,473	3,378	3,285	3,196	3,110	3,026	2,945	2,867	2,792	2,719	2,648	2,339	2,067	1,837
Capitalized Expense	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL OTHER OPERATING EXPENSES	0	0	0	5,439	5,330	5,224	5,122	5,023	4,928	4,835	4,746	4,660	4,576	4,495	4,417	4,342	4,269	4,198	3,889	3,617	3,387
OPERATING PROFIT	0	0	0	4,112	12,958	13,064	13,166	13,265	13,361	13,453	13,542	13,629	13,712	13,793	13,871	13,946	14,019	14,090	14,399	14,671	14,901
NON-OPERATING INCOME & EXPENSES																					
Amortization Loan Expense	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Loan #1 Amortized Loan	380	380	380	362	344	324	304	283	260	237	212	186	158	130	100	68	35	0	0	0	0
Interest Loan #2 Amortized Loan	0	1,519	1,519	1,449	1,375	1,297	1,216	1,130	1,040	946	847	743	634	519	399	272	139	0	0	0	0
Interest Loan #3 Amortized Loan	0	0	1,899	1,811	1,719	1,622	1,520	1,413	1,300	1,183	1,059	929	792	649	498	340	174	0	0	0	0
Capitalized Interest	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL INTEREST EXPENSES	380	1,899	3,798	3,622	3,437	3,243	3,040	2,826	2,601	2,365	2,117	1,857	1,584	1,298	996	680	348	0	0	0	0
INCOME BEFORE TAXES	(380)	(1,899)	(3,798)	490	9,521	9,821	10,127	10,440	10,760	11,088	11,425	11,771	12,128	12,495	12,874	13,266	13,671	14,090	14,399	14,671	14,901
INCOME TAXES																					
Current FIT	0	0	0	0	0	0	0	0	0	0	846	6,116	6,320	6,500	6,672	6,842	7,016	7,193	7,355	7,301	7,337
Deferred FIT	0	0	0	228	4,423	4,562	4,704	4,849	4,998	5,150	4,460	(648)	(687)	(696)	(692)	(650)	(665)	(649)	(647)	(486)	(416)
TOTAL FIT	0	0	0	228	4,423	4,562	4,704	4,849	4,998	5,150	5,307	5,468	5,633	5,804	5,980	6,162	6,350	6,545	6,688	6,815	6,921
NET INCOME	(380)	(1,899)	(3,798)	262	5,099	5,259	5,423	5,590	5,762	5,938	6,118	6,304	6,495	6,691	6,894	7,104	7,321	7,545	7,711	7,857	7,979

OPTION A
PROJECTED STATEMENT OF INCOME-TABLE 5-7

PROJECTED BALANCE SHEET	Calendar Year	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2012	2017	2022
==========	Project Year	-3	-2	-1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	20	25	30
WILLAMS LAKE - OPTION A		---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
ASSETS																						
Cash		(300)	(2,279)	(6,077)	(5,876)	2,411	11,425	20,440	29,402	38,526	47,502	55,072	59,269	62,059	64,680	67,142	69,450	71,600	73,590	118,125	162,402	206,479
Temporary Investments		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Accounts Receivable		0	0	0	1,066	1,812	1,812	1,812	1,812	1,812	1,812	1,812	1,812	1,812	1,812	1,812	1,812	1,812	1,812	1,812	1,812	1,812
Other Current Assets		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL CURRENT ASSETS		(300)	(2,279)	(6,077)	(4,810)	4,223	13,237	22,260	31,294	40,339	49,394	57,685	61,081	63,871	66,492	68,955	71,262	73,413	75,402	119,937	164,215	208,291
Cons. Work in Progress		11,394	56,972	113,945	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Prop. Plant & Equipment*		0	0	0	113,944	114,544	115,144	115,744	116,344	116,944	117,544	118,144	118,744	119,344	119,944	120,544	121,144	121,744	122,344	125,344	128,344	131,344
- Accumulated Depreciation [Book]*		0	0	0	3,889	7,669	11,343	14,915	18,388	21,766	25,051	28,247	31,356	34,382	37,328	40,195	42,987	45,706	48,354	60,628	71,487	81,117
NET PROPERTY, PLANT & EQUIPMENT		11,394	56,972	113,945	110,055	106,875	103,801	100,829	97,956	95,179	92,493	89,898	87,388	84,962	82,617	80,349	78,157	76,039	73,990	64,717	56,857	50,228
Unamortized Debt Expenses		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL ASSETS		11,015	54,693	107,867	105,246	111,098	117,038	123,090	129,250	135,517	141,888	147,582	148,470	148,833	149,109	149,304	149,420	149,451	149,392	184,654	221,072	258,519
CURRENT LIABILITIES																						
Accounts Payable		0	0	0	281	309	309	309	309	309	309	309	309	309	309	309	309	309	309	309	309	309
Other Payables		0	0	0	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127
Income Tax Payable		0	0	0	0	0	0	0	0	0	0	70	503	519	534	548	562	577	591	596	600	603
TOTAL CURRENT LIABILITIES		0	0	0	408	437	437	437	437	437	437	506	939	956	971	985	999	1,013	1,028	1,033	1,037	1,040
BANK LOANS																						
Loan #1 Amortized Loan		7,596	7,596	7,596	7,244	6,875	6,487	6,079	5,651	5,202	4,730	4,235	3,715	3,169	2,595	1,993	1,361	697	0	0	0	0
Loan #2 Amortized Loan		0	30,385	30,385	28,977	27,499	25,946	24,316	22,604	20,807	18,920	16,939	14,858	12,674	10,380	7,972	5,443	2,788	0	0	0	0
Loan #3 Amortized Loan		0	0	37,982	36,221	34,373	32,433	30,395	28,256	26,009	23,650	21,174	18,573	15,843	12,975	9,965	6,804	3,485	0	0	0	0
Loan Bond		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOANS		7,596	37,982	75,963	72,443	68,746	64,865	60,790	56,511	52,018	47,301	42,347	37,146	31,685	25,951	19,930	13,608	6,970	0	0	0	0
DEFERRED FIT		0	0	0	228	4,650	9,212	13,916	18,765	23,763	28,913	33,374	32,725	32,039	31,302	30,651	29,970	29,305	28,656	25,669	23,082	20,865
Common Stock		3,798	18,991	37,982	37,982	37,982	37,982	37,982	37,982	37,982	37,982	37,982	37,982	37,982	37,982	37,982	37,982	37,982	37,982	37,982	37,982	37,982
Grant				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Stock Repurchase		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retained Earnings		(300)	(2,279)	(6,077)	(5,815)	(716)	4,543	9,966	15,556	21,318	27,256	33,374	39,677	46,172	52,863	59,757	66,861	74,182	81,727	119,971	158,973	198,632
TOTAL OWNER'S EQUITY		3,418	16,712	31,904	32,167	37,265	42,524	47,947	53,538	59,299	65,237	71,355	77,659	84,153	90,845	97,739	104,843	112,163	119,708	157,953	196,954	236,614
TOTAL OWNER'S EQUITY & LIABILITIES		11,015	54,693	107,867	105,246	111,099	117,038	123,090	129,250	135,517	141,888	147,582	148,470	148,833	149,109	149,304	149,420	149,451	149,392	184,654	221,072	258,519
RETAINED EARNINGS CALCULATION																						
Retained Earnings (Start of Year)		0	(300)	(2,279)	(6,077)	(5,815)	(716)	4,543	9,966	15,556	21,318	27,256	33,374	39,677	46,172	52,863	59,757	66,861	74,182	112,260	151,116	190,653
Income (Loss) for year		(300)	(1,899)	(3,798)	262	5,099	5,259	5,423	5,590	5,762	5,938	6,118	6,304	6,494	6,691	6,894	7,104	7,321	7,545	7,711	7,857	7,979
Less Dividends Paid		0																				
Retained Earnings (End of Year)		(300)	(2,279)	(6,077)	(5,815)	(716)	4,543	9,966	15,556	21,318	27,256	33,374	39,677	46,172	52,863	59,757	66,861	74,182	81,727	119,971	158,973	198,632

OPTION A
PROJECTED BALANCE SHEET - TABLE 5-8

PROJECTED CASH STATEMENT	Calendar Year	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2012	2017	2022
==========	Project Year	-3	-2	-1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	20	25	30
WILLIAMS LAKE - OPTION A		---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
RECEIPTS																						
Operating Revenues		0	0	0	11,905	21,304	22,050	22,050	22,050	22,050	22,050	22,050	22,050	22,050	22,050	22,050	22,050	22,050	22,050	22,050	22,050	22,050
Investments Revenues		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL RECEIPTS		0	0	0	11,905	21,304	22,050	22,050	22,050	22,050	22,050	22,050	22,050	22,050	22,050	22,050	22,050	22,050	22,050	22,050	22,050	22,050
DISBURSEMENTS																						
Operating Expenses		0	0	0	3,138	3,734	3,762	3,762	3,762	3,762	3,762	3,762	3,762	3,762	3,762	3,762	3,762	3,762	3,762	3,762	3,762	3,762
Interest Expenses		380	1,899	3,798	3,622	3,437	3,243	3,040	2,826	2,601	2,365	2,117	1,857	1,584	1,298	996	680	348	0	0	0	0
Current FIT		0	0	0	0	0	0	0	0	0	0	777	5,683	6,303	6,486	6,658	6,828	7,001	7,179	7,254	7,300	7,327
Property Taxes and Insurance		0	0	0	1,423	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550
TOTAL DISBURSEMENTS		380	1,899	3,798	8,183	8,721	8,555	8,351	8,137	7,913	7,677	8,206	12,852	13,199	13,095	12,966	12,821	12,662	12,491	12,566	12,612	12,649
CASH FROM OPERATIONS		(380)	(1,899)	(3,798)	3,722	12,583	13,495	13,699	13,913	14,137	14,373	13,844	9,198	8,851	8,955	9,084	9,229	9,388	9,559	9,484	9,438	9,401
BEGINNING CASH BALANCE		0	(380)	(2,279)	(6,077)	(5,876)	2,411	11,425	20,448	29,482	38,526	47,582	55,872	59,269	62,059	64,680	67,142	69,450	71,600	109,241	153,564	197,678
CAPITAL AQUISITION*		11,394	45,578	56,972	0	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
DIVIDENDS		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FINANCING PROCEEDS																						
Loan Proceeds		7,596	30,385	37,982	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Loan Repayments		0	0	0	(3,520)	(3,696)	(3,881)	(4,075)	(4,279)	(4,493)	(4,718)	(4,953)	(5,201)	(5,461)	(5,734)	(6,021)	(6,322)	(6,638)	(6,970)	0	0	0
Common Stock		3,798	15,193	18,991	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Grant				0																		
TOTAL FINANCING PROCEEDS		11,394	45,578	56,972	(3,520)	(3,696)	(3,881)	(4,075)	(4,279)	(4,493)	(4,718)	(4,953)	(5,201)	(5,461)	(5,734)	(6,021)	(6,322)	(6,638)	(6,970)	0	0	0
ENDING CASH BALANCE		(380)	(2,279)	(6,077)	(5,876)	2,411	11,425	20,448	29,482	38,526	47,582	55,872	59,269	62,059	64,680	67,142	69,450	71,600	73,590	118,125	162,402	206,479

OPTION A
CASH FLOW FROM OPERATIONS
& EXTERNAL CASH - TABLE 5-9

CASH FLOW FROM OPERATIONS & EXTERNAL CASH — WILLAMS LAKE - OPTION A	Calendar Year	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2012	2017	2022
	Project Year	-3	-2	-1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	20	25	30
NET INCOME		(380)	(1,899)	(3,798)	262	5,099	5,259	5,423	5,590	5,762	5,938	6,118	6,304	6,494	6,691	6,894	7,104	7,321	7,545	7,711	7,857	7,979
PLUS: Depreciation [Book]*		0	0	0	3,889	3,780	3,674	3,572	3,473	3,378	3,285	3,196	3,110	3,026	2,945	2,867	2,792	2,719	2,648	2,339	2,067	1,837
Interest Expense		380	1,899	3,798	3,622	3,437	3,243	3,040	2,826	2,601	2,365	2,117	1,857	1,584	1,298	996	680	348	0	0	0	0
Tax Effect of Interest		(176)	(882)	(1,764)	(1,682)	(1,597)	(1,506)	(1,412)	(1,312)	(1,208)	(1,099)	(984)	(863)	(736)	(603)	(463)	(316)	(162)	0	0	0	0
Income Tax Accrual		0	0	0	228	4,423	4,562	4,704	4,849	4,998	5,150	4,460	(648)	(687)	(696)	(692)	(680)	(665)	(649)	(567)	(486)	(416)
Amortization Debt Expense		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL ADDITIONS		203	1,017	2,034	6,056	10,043	9,973	9,903	9,835	9,768	9,702	8,790	3,456	3,188	2,944	2,709	2,476	2,240	2,000	1,772	1,581	1,421
LESS: Current FIT		0	0	0	0	0	0	0	0	0	0	846	6,116	6,320	6,500	6,672	6,842	7,016	7,193	7,255	7,301	7,337
Temporary Investment Income		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tax Effects Temporary Investment		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL DEDUCTIONS		0	0	0	0	0	0	0	0	0	0	846	6,116	6,320	6,500	6,672	6,842	7,016	7,193	7,255	7,301	7,337
AFTER TAX FUNDS BEFORE CHANGES IN WORKING CAPITAL		(176)	(882)	(1,764)	6,319	15,142	15,232	15,326	15,426	15,530	15,640	14,062	3,643	3,362	3,135	2,931	2,737	2,545	2,351	2,228	2,136	2,063
PLUS: Increase in Accounts Payable		0	0	0	281	28	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Increase in Other Accounts Payable		0	0	0	127	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Increase in Taxes Payable		0	0	0	0	0	0	0	0	0	0	846	5,270	204	188	172	170	173	178	11	8	7
TOTAL ADDITIONS		0	0	0	408	28	0	0	0	0	0	846	5,270	204	188	172	170	173	178	11	8	7
LESS: Increase in Accounts Receivable		0	0	0	1,066	746	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Increase in Other Current Assets		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL DEDUCTIONS		0	0	0	1,066	746	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CASH FROM OPERATING CYCLE		(176)	(882)	(1,764)	5,661	14,423	15,232	15,326	15,426	15,530	15,640	14,908	8,913	3,566	3,315	3,103	2,908	2,718	2,529	2,239	2,145	2,070
LESS: Fixed Capital Investment		11,396	45,578	56,972	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capitalized Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capitalized Interest		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CASH FROM OPERATIONS BEFORE EXTERNAL FINANCING & INTEREST INCOME & EXPENSES		(11,571)	(46,460)	(58,737)	5,661	14,423	15,232	15,326	15,426	15,530	15,640	14,908	8,913	3,566	3,315	3,103	2,908	2,718	2,529	2,239	2,145	2,070
- Change in Temporary Investment		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
+ Temporary Investment After Tax		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
- Interest Expenses After Tax		203	1,017	2,034	1,940	1,841	1,737	1,628	1,513	1,393	1,266	1,134	995	848	695	534	364	187	0	0	0	0
CASH BEFORE EXTERNAL FINANCINGS		(11,774)	(47,477)	(60,771)	3,722	12,583	13,495	13,699	13,913	14,137	14,373	13,774	7,918	2,718	2,620	2,569	2,543	2,532	2,529	2,239	2,145	2,070
- Debt Expenses		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
+ Increase in Debt		7,596	30,385	37,982	(3,520)	(3,696)	(3,881)	(4,075)	(4,279)	(4,493)	(4,718)	(4,953)	(5,201)	(5,461)	(5,734)	(6,021)	(6,322)	(6,638)	(6,970)	0	0	0
+ Stock Sale Proceeds		3,798	15,193	18,991	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
+ Grant				0																		
- Dividends & Repurchase		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EQUITY CASH FLOWS		(3,798)	(15,193)	(18,991)	201	8,886	9,614	9,624	9,634	9,644	9,656	8,821	2,717	(2,743)	(3,114)	(3,452)	(3,779)	(4,106)	(4,441)	2,239	2,145	2,070

IRR guessing at rate of 25.00% over 20 years ..: 9.99%
IRR guessing at rate of 25.00% over 30 years ..: 10.11%

OPTION A
PROJECTED CASH STATEMENT - TABLE 5-10

OPTION A
FINANCING - TABLE 5-11

FINANCING	Calender Year	1990	1991	1992
=========	Project Year	-3	-2	-1
WILLIAMS LAKE - OPTION A		----	----	----
LOAN SPECIFICATION		LOAN 1	LOAN 2	LOAN 3
Percent of Capital Costs		10.00%	40.00%	50.00%
Principal Amount		7,596	30,385	37,982
Interest Rate		5.00%	5.00%	5.00%
Term (Years)		15	15	15
EQUITY REQUIRED		3,798	15,193	18,991
ASSISTANCE GRANT				0
TOTAL FUNDS REQUIRED		11,394	45,578	56,972
TOTAL FUNDS		11,394	45,578	56,972

WILLIAMS LAKE THERMAL PLANT - OPTION A

CAPITAL COST ESTIMATE FOR FINANCING PURPOSES: 113,945

DEBT/EQUITY RATIO 2 TO 1

AMORTIZATION SCHEDULE FOR LOAN #1

Amount of Loan	$7,596
Payments per Year	1
Term of Loan (Years)	15
Annual Interest Rate	5.00%
Payment Each Period	732

Years	Balance	Principal	Int.
1	7,244	352	380
2	6,875	370	362
3	6,487	388	344
4	6,079	408	324
5	5,651	428	304
6	5,202	449	283
7	4,730	472	260
8	4,235	495	237
9	3,715	520	212
10	3,169	546	186
11	2,595	573	158
12	1,993	602	130
13	1,361	632	100
14	697	664	68
15	0	697	35

AMORTIZATION SCHEDULE FOR LOAN #2

Amount of Loan	$30,385
Payments per Year	1
Term of Loan (Years)	15
Annual Interest Rate	5.00%
Payment Each Period	2,927

Years	Balance	Principal	Int.
1	28,977	1,408	1,519
2	27,499	1,479	1,449
3	25,946	1,552	1,375
4	24,316	1,630	1,297
5	22,604	1,712	1,216
6	20,807	1,797	1,130
7	18,920	1,887	1,040
8	16,939	1,981	946
9	14,858	2,080	847
10	12,674	2,184	743
11	10,380	2,294	634
12	7,972	2,408	519
13	5,443	2,529	399
14	2,788	2,655	272
15	0	2,788	139

AMORTIZATION SCHEDULE FOR LOAN #3

Amount of Loan	$37,982
Payments per Year	1
Term of Loan (Years)	15
Annual Interest Rate	5.00%
Payment Each Period	3,659

Years	Balance	Principal	Int.
1	36,221	1,760	1,899
2	34,373	1,848	1,811
3	32,433	1,941	1,719
4	30,395	2,038	1,622
5	28,256	2,139	1,520
6	26,009	2,246	1,413
7	23,650	2,359	1,300
8	21,174	2,477	1,183
9	18,573	2,601	1,059
10	15,843	2,731	929
11	12,975	2,867	792
12	9,965	3,010	649
13	6,804	3,161	498
14	3,485	3,319	340
15	0	3,485	174

LOAN #1

Years	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Balance	7,244	6,875	6,487	6,079	5,651	5,202	4,730	4,235	3,715	3,169	2,595	1,993	1,361	697	0
Principal	352	370	388	408	428	449	472	495	520	546	573	602	632	664	697
Interest	380	362	344	324	304	283	260	237	212	186	158	130	100	68	35

LOAN #2

Years	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Balance	28,977	27,499	25,946	24,316	22,604	20,807	18,920	16,939	14,858	12,674	10,380	7,972	5,443	2,788	0
Principal	1,408	1,479	1,552	1,630	1,712	1,797	1,887	1,981	2,080	2,184	2,294	2,408	2,529	2,655	2,788
Interest	1,519	1,449	1,375	1,297	1,216	1,130	1,040	946	847	743	634	519	399	272	139

LOAN #3

Years	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Balance	36,221	34,373	32,433	30,395	28,256	26,009	23,650	21,174	18,573	15,843	12,975	9,965	6,804	3,485	0
Principal	1,760	1,848	1,941	2,038	2,139	2,246	2,359	2,477	2,601	2,731	2,867	3,010	3,161	3,319	3,485
Interest	1,899	1,811	1,719	1,622	1,520	1,413	1,300	1,183	1,059	929	792	649	498	340	174

DEFERRED TAX CALCULATION	Calender Year	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2012	2017	2022
==========	Project Year	-3	-2	-1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	20	25	30
WILLIAMS LAKE - OPTION A		---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
TAX ACCRUAL CALCULATION																						
Income Before Taxes		(380)	(1,899)	(3,798)	490	9,521	9,821	10,127	10,440	10,760	11,088	11,425	11,771	12,128	12,495	12,874	13,266	13,671	14,090	14,399	14,671	14,901
Tax Rate		46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%
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Income Tax Accrual		(176)	(882)	(1,764)	228	4,423	4,562	4,704	4,849	4,998	5,150	5,307	5,468	5,633	5,804	5,980	6,162	6,350	6,545	6,688	6,815	6,921
CURRENT FEDERAL INCOME TAXES CALCULATION																						
Income Before Taxes		(380)	(1,899)	(3,798)	490	9,521	9,821	10,127	10,440	10,760	11,088	11,425	11,771	12,128	12,495	12,874	13,266	13,671	14,090	14,399	14,671	14,901
+ Depreciation [Book]*		0	0	0	3,889	3,780	3,674	3,572	3,473	3,378	3,285	3,196	3,110	3,026	7,945	2,867	2,792	2,719	2,648	2,339	2,067	1,837
Income to Tax [Prior LCF & CCA]		(380)	(1,899)	(3,798)	4,379	13,301	13,495	13,699	13,913	14,137	14,373	14,621	14,881	15,154	15,441	15,742	16,058	16,390	16,738	16,738	16,738	16,738
Loss Carry Forward																						
Opening Balance		0	(380)	(2,279)	(6,077)	(1,698)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
+ Income to Tax [Prior LCF & CCA]		(380)	(1,899)	(3,798)	4,379	13,301	13,495	13,699	13,913	14,137	14,373	14,621	14,881	15,154	15,441	15,742	16,058	16,390	16,738	16,738	16,738	16,738
Balance Carry Forward		(380)	(2,279)	(6,077)	(1,698)	11,603	13,495	13,699	13,913	14,137	14,373	14,621	14,881	15,154	15,441	15,742	16,058	16,390	16,738	16,738	16,738	16,738
Income to Tax [Prior to CCA]		0	0	0	0	11,603	13,495	13,699	13,913	14,137	14,373	14,621	14,881	15,154	15,441	15,742	16,058	16,390	16,738	16,738	16,738	16,738
Capital Cost Allowance Calculation																						
Balance from previous year		0	0	0	0	21,304	42,211	45,864	41,594	33,215	22,632	10,795	0	0	0	0	0	0	0	0	0	0
+ Total Annual CCA [Depr. Tax]*		0	0	0	21,304	32,509	17,149	9,429	5,533	3,554	2,537	2,083	1,714	1,548	1,446	1,378	1,327	1,286	1,252	1,119	1,020	942
Total CCA available		0	0	0	21,304	53,814	59,359	55,293	47,127	36,769	25,169	12,799	1,714	1,548	1,446	1,378	1,327	1,286	1,252	1,119	1,020	942
- Income to Tax [Prior to CCA]		0	0	0	0	11,603	13,495	13,699	13,913	14,137	14,373	14,621	14,881	15,154	15,441	15,742	16,058	16,390	16,738	16,738	16,738	16,738
CCA Used		0	0	0	0	11,603	13,495	13,699	13,913	14,137	14,373	12,799	1,714	1,548	1,446	1,378	1,327	1,286	1,252	1,119	1,020	942
Balance Cumulative CCA		0	0	0	21,304	42,211	45,864	41,594	33,215	22,632	10,795	0	0	0	0	0	0	0	0	0	0	0
Taxable Income		0	0	0	0	0	0	0	0	0	0	1,022	13,167	13,606	13,994	14,364	14,731	15,103	15,486	15,619	15,718	15,797
Effective Tax Rate		46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%	46.45%
Current FIT		0	0	0	0	0	0	0	0	0	0	846	6,116	6,320	6,500	6,672	6,842	7,016	7,193	7,255	7,301	7,337
DEFFERED FEDERAL INCOME TAXES CALCULATION																						
Income Tax Accrual		0	0	0	228	4,423	4,562	4,704	4,849	4,998	5,150	5,307	5,468	5,633	5,804	5,980	6,162	6,350	6,545	6,688	6,815	6,921
- Current FIT		0	0	0	0	0	0	0	0	0	0	846	6,116	6,320	6,500	6,672	6,842	7,016	7,193	7,255	7,301	7,337
Deferred FIT		0	0	0	228	4,423	4,562	4,704	4,849	4,998	5,150	4,460	(648)	(687)	(696)	(692)	(680)	(665)	(649)	(567)	(486)	(416)

OPTION A
DEFERRED TAX CALCULATION - TABLE 5-12

APPENDIX 6

WOODWASTE SUPPLY STUDY

(X7801/1)

APPENDIX 6 - WOODWASTE SUPPLY ANALYSIS AND REFERENCES

FUEL SUPPLY ANALYSIS PROCEDURES

The procedure used to determine the BDU volume, the moisture content and the higher heating value of the fuel is explained in this appendix.

The fuel supply is composed of log yard wood debris, wood lily pads, bark removed by mechanical debarkers on the mill deck, sawdust generated in the production of lumber and planer shavings from the lumber surfacing operations. Except for a small quantity used for mill steam, all of these fuel sources are currently burned in the incinerators (teepee burners) located on each mill site.

Log Yard Debris

The estimates of log yard wood debris range from a low of .75 percent to a high of 1.5 percent of the total log usage. These estimates were made by the individual operators. The source of the debris is breakage of primarily small logs while they are being handled in the yard. The log yard debris has the same moisture content as the chips generated from the facility; its higher listing value is the same as wood of the respective species.

Lily Pad Volumes

Lily pads are generated when a log is bucked on the mill deck. A lily pad is a 1 to 3 inch segment of log sawn off to square up the end of the log or to cut out a defect. Some mills cut lily pads from almost every log while others buck lily pads only infrequently. The operators estimated their respective lily pad generation percentages of the logs used. The estimates varied from 0 percent to 1.5 percent.

Bark

The bark estimates are based upon work done by Forintek Canada Corporation and reported in Conversion Factors for the Forest Products Industry in Western Canada.[1]

The bark volume calculation involved several steps. First, the gross bark volume was determined using data provided by Forintek. Forintek presents a chart of bark as a percent of the stem wood volume by species.

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[1] Nielson, R.W. et al. Conversion Factors for the Forest Products Industry in Western Canada. Forintek Canada Corp., Vancouver, B.C. 1985.

Second, the bark void percentage was used to determine total voids for each species. Douglas fir voids have been determined by Forintek; bark voids for the other species are estimates based on DBA and Forintek experience. The voids are then subtracted from the gross bark volume to determine the net bark percentage for a stem with 100 percent of its bark present.

The next step is to determine how much bark is lost in the logging, transportation and handling process. This is dependent upon the logging system used.

All of the operators reported using or planning to use feller bunchers and stroke delimbers for the small logs in all possible locations. The bark loss from the use of mechanical delimbing is estimated to be 30% for Lodgepole Pine with somewhat lower losses for Engelman Spruce, Sub Alpine Fir and Western Red Cedar. However, as little Douglas Fir is mechanically logged, the losses are estimated to be just 15%. The estimates were determined by the writer's observation with the mill operators and based upon discussion with them and Forintek personnel.

The Bark Calculation for five species is shown below:

Bark Calculations	Williams Lake, BC Species		
Species	Douglas Fir	Lodgepole Pine	Engelman Spruce
Bark As Gross % Of Wood	30.4	11.2	14.9
Percent Of Voids In Bark	27.0	10.0	10.0
Net Bark % On Tree	22.2	10.1	13.4
Est % Loss Woods to Mill	15.0	30.0	20.0
Bark As % Of Roundwood on Mill Deck	18.9	7.1	10.7

Species	Sub Alpine Fir	Western Red Cedar	
Bark As Gross % Of Wood		15.6	17.9
Percent Of Voids In Bark		15.0	15.0
Net Bark % On Tree	13.3%	15.2	
Est % Loss Woods To Mill		20.0	10.0
Bark As % Of Roundwood on Mill Deck		10.6	13.7

Sawdust

The sawdust category includes an allowance for chip fines. The estimate for sawdust is based upon discussions with each manager and on calculations of the kerfs being used in the mills. The sawdust estimates range from 8 to 11 percent of the log volume.

Shavings

The shavings are calculated by deducting from the volume (cubic feet per thousand board feet or ft^3/kBF) of the lumber sawn in the sawmill the ft^3/kBF of shrinkage and the final lumber ft^3/kBF volume. The remaining wood is shavings.

Bone Dry Unit Calculation

Once the cubic feet of the various products is calculated, the cubic feet are converted to BDU's based upon the density of the bark or wood of a specific species. The densities for the wood and bark are also presented in the Forintek publication.

Once the densities are known, it is a simple calculation to determine the BDU volume of each.

Moisture Content and Higher Heating Value

The moisture content of each residue product was obtained from the individual operators. The combined weighted average moisture content was then calculated using the moisture contents and percentages by volume of the component products.

Forintek's Higher Heating Values (BTU per Dry Pound) were used when available. Those not available directly were estimated with the assistance of Forintek personnel.

Using the same methods, weighted averages were calculated to determine the average Higher Heating Values.

Regional Analyses

Data presented in this appendix were derived from reported hog fuel production and use by mills in the Cariboo Development Region. The data are divided into sections by electoral regions: Cariboo, North Prince George and South Prince George.

The forest management areas (FMAs) included in the assessment areas follows:

9 Robson
10 South Cariboo
11 Central Cariboo
12 North Cariboo
13 Prince George East

The data shows the total hog fuel produced by each mill, its use within the plant, and the amount and disposal of the surplus. Surplus, which is currently incinerated or landfilled, is considered available for cogeneration use.

The data derived from two sources: responses to a 1988 survey (1987 data reported) and a 1987 report provided by the Canadian Forestry Service.[2] An asterisk (*) by company name indicates the data source is the Forestry Service Report; all other data is from the survey.

[2]Reid, Collins and Associates Ltd. 1986 Hog Fuel Availability Study: North Coastal and Interior Regions of B.C. (Canadian Forestry Service, Vancouver, B.C. December 1987).

The following mills were contacted but provided no data: Carrier Lumber at Anahim Lake, Eberding Timber, Perron Sawmills, Brink Forest Products and Midget mills.

Results of Analyses

The following pages contain the detailed results of the regional and local assessment of woodwaste availability.

The regional results have been developed from existing data and the questionnaires sent to all the regional mills. These results are shown in Table 6-1 and 6-2.

It should be noted that the sawmills in Williams Lake are evaluated in more detail in order to ensure accurate thermal plat size selection.

HOG FUEL PRODUCTION, MILL USE AND SURPLUS FOR 1986-7 (BDU's)

Williams Lake Cogeneration Study

Company	Mill Type	City	For Mgt Reg	Total Hog Fuel Available	On-Site Hog Fuel Use: Steam/ Power/ Heat	On-Site Hog Fuel Use: Pulp Furnish	On-Site Hog Fuel Use: Total On-Site Use	SURPLUS	Disposition of Mill Surplus: Steam/ Power	Disposition of Mill Surplus: Pulp Furnish	Disposition of Mill Surplus: Local Sales	Disposition of Mill Surplus: Land-fill	Disposition of Mill Surplus: Incin-erated	NET AVAILABLE SURPLUS
Electoral Region: Cariboo														
* Ainsworth Lumber Co Ltd	Stud	100 Mile House	10	55000	16000	0	16000	39000	0	0	0	0	39000	39000
* Ainsworth Lumber Co Ltd	Stud	100 Mile House	10	100000	20000	0	20000	80000	0	0	0	0	80000	80000
* C & C Wood Products Ltd	Sawmill	Quesnel	12	6000	0	0	0	6000	2500	0	0	0	3500	3500
* Slocan Forest Products	Sawmill	Quesnel	12	101000	0	0	0	101000	49900	0	0	0	51100	51100
* Starline Lumber Inc.	Sawmill	Williams Lake	10	30000	0	0	0	30000	0	0	0	0	30000	30000
* Weldwood of Canada Ltd.	Sawmill	100 Mile House	10	70000	16000	0	16000	54000	0	0	0	0	54000	54000
* Weldwood of Canada Ltd.	S Ply/Ven	Quesnel	12	24600	10000	0	10000	14600	0	0	0	0	14600	14600
* Weldwood of Canada Ltd.	Sawmill	Quesnel	12	43000	6000	0	6000	37000	14000	0	0	0	23000	23000
* West Fraser Mills Ltd.	Sawmill	Quesnel	12	125000	35000	0	35000	90000	11400	0	0	0	78000	78000
Carrier Lumber Ltd.	Sawmill	Anahim Lake	11	0			0	0						0
Eberding Timber Ltd.	Sawmill	Quesnel	12	0			0	0						0
Perron Sawmills Ltd.	Sawmill	Forest Grove	10	0			0	0						0
Tolko Industries Ltd.	Sawmill	Quesnel	12	93800	0	0	0	93800	62000		0	0	31800	31800
Total for Cariboo region:				648400	103000	0	103000	545400	139800		0	0	405000	405000
Electoral Region: Pr. George North														
* Polar Forest Industries	Sawmill	Bear Lake	13	60000	0	0	0	60000	4500	0	0	0	55500	55500
Finlay Forest Industries	Sawmill	Mackenzie	13	0	0	0	0	0	0	0	0	0	0	0
Fletcher Challenge (BCFP)	Dimension	Mackenzie	13	74400	0	0	0	74400	28320	0	0	744	45336	46080
Fletcher Challenge (BCFP)	Dimension	Mackenzie	13	58380	0	0	0	58380	0	0	50380	0	8000	8000
Fletcher Challenge (BCFP)	Stud	Mackenzie	13	50480	0	0	0	50480	50480	0	0	0	0	0
The Pas Lumber Co. Ltd.	Sawmill/P	Bear Lake	13	37286	7230	0	7230	30056	0	0	0	0	30056	30056
Total for Pr. George North region:				280546	7230	0	7230	273316	83300	0	50380	744	138892	139636
Electoral Region: Pr. George South														
* Canadian Forest Product	Sawmill	Prince George	13	50000	5000	0	5000	45000	0	0	0	0	45000	45000

Table 6 -] Disposition of Regional Mill Surplus

Williams Lake Cogeneration Study

Company	Mill Type	City	For Mgt Reg	Total Hog Fuel Available	On-Site Hog Fuel Use: Steam/ Power/ Heat	On-Site Hog Fuel Use: Pulp Furnish	On-Site Hog Fuel Use: Total On-Site Use	SURPLUS	Disposition of Mill Surplus: Steam/ Power	Disposition of Mill Surplus: Pulp Furnish	Disposition of Mill Surplus: Local Sales	Disposition of Mill Surplus: Land- fill	Disposition of Mill Surplus: Incin- erated	NET AVAILABLE SURPLUS
* Carrier Lumber Ltd.	Sawmill	Prince George	13	80000	0	0	0	80000	0	0	0	0	80000	80000
* Clear Lake Sawmills	Sawmill	Prince George	13	56700	6700	0	6700	50000	0	0	0	0	50000	50000
* Clearwater Timber Produ	Sawmill	Valemount	9	30000	0	0	0	30000	0	0	0	30000	0	30000
* Dunkley Lumber Ltd.	Sawmill	Prince George	13	60000	0	0	0	60000	0	0	0	0	60000	60000
* Hauer Bros. Lumber Ltd.	Sawmill	Valemount	9	6000	0	0	0	6000	0	0	0	0	6000	6000
* Lakeland Mills Ltd.	Sawmill	Prince George	13	50000	6000	0	6000	44000	28000	0	0	0	16000	16000
* Netherlands Overseas Mi	Sawmill	Prince George	13	120000	30000	0	30000	90000	51000	0	0	0	39000	39000
* Prince George Wood Pavg	Sawmill	Prince George	13	40000	0	0	0	40000	5300	0	0	0	34700	34700
* Rustad Bros. & Co. Ltd.	Sawmill	Prince George	13	105000	43500	0	43500	61500	19500	0	0	0	42000	42000
* Zeidler Forest Industri	S Ply/Ven	McBride	9	15000	0	0	0	15000	0	0	0	0	15000	15000
* Zeidler Forest Industri	Stud	McBride	9	9000	0	0	0	9000	0	0	0	0	9000	9000
Brink Forest Products Ltd	Sawmill	Prince George	13	0			0	0						0
Midget Mills	Sawmill	McBride	9	0			0	0						0
Northwood Pulp & Timber	S Ply/Ven	Prince George	13	14700	0	0	0	14700	7300	0	0	0	7400	7400
Northwood Pulp & Timber	Sawmill	Prince George	13	93700	0	0	0	93700	93700	0	0	0	0	0
Northwood Pulp & Timber	Sawmill	Shelley	13	50500	0	0	0	50500	50500	0	0	0	0	0
Northwood Pulp & Timber	Sawmill	Upper Fraser	13	84500	15700	0	15700	68800	14600	0	0	0	54200	54200
The Pas Lumber Co. Ltd.	Planer	Prince George	13	17000	12000	0	12000	5000	0	0	0	0	5000	5000
Total for Pr. George South region:				882100	118900	0	118900	763200	269900	0	0	30000	463300	493300
Total for study area:				1811046	229130	0	229130	1581916	493000		50380	30744	1007192	1037936

Table 6 - 2 Disposition of Regional Mill surplus

REPORT X7801/1
CARIBOO WOODWASTE STUDY

MINISTER OF STATE
CARIBOO DEVELOPMENT REGION
VICTORIA BRITISH COLUMBIA

DATE 9 MARCH 1989

DON BAACH & ASSOCIATES

SAWMILL WOODWASTE ANALYSIS DATA

GLOSSARY OF TERMS

CED - Cedar

CF - Cubic Feet

CM - Cubic Metres

DFir - Douglas Fir

LPP - Log Pole Pine

MBF - Million Board Feet

MC - Moisture Content

Rgh - Rough

S-A Fir - Sub Alpine Fir

Table 6-3 - Woodwaste Availability Lignum Ltd.

Recovery per m^3 debarked logs — Species: Doug Fir

	ft^3/m^3	% Recovery	BDU/m^3
Net Lumber	15.6	44.2	
Green Chips	14.6	41.4	0.171
Dry Chips			
Sawdust	3.9	11.0	0.045
Shavings	1.2	3.4	0.014
Mix Shrinkage			
Total debarked logs	35.3	100.0	
Bark	6.7	18.9	0.086
Rough Lumber	18.0	50.93	0.272

Material Flow Report

Species: Doug Fir

		Volume /Hour	Volume /Day	Volume /Month	Volume /Year
Green Chips	BDU	28.0	543	11324	34446
Dry Chips	BDU	0	0	0	0
Sawdust	BDU	7.4	143	2980	9065
Shavings	BDU	2.3	44	927	2820
Bark	BDU	14.1	273	5695	17324
Logs	m^3	163.8	3178	66219	201441

Key Assumptions

Species: Doug Fir

	Sold Rough Grn	Sold S4S Grn	Sold SRS Dry	Weighted Average
Percent Volume Sold	0	100.0	0	
Adjusted % Volume ft^3	0	100.0	0	
Prod Sawn Size Of ft^3/MBF	67.1	66.1	67.1	66.10
Percent Vol Shrinkage	0	0	5.0	
Percent Planer Trim	7.0	7.0	7.0	7.00
Sold Size Avg ft^3/MBF	67.1	61.7	58.3	61.70
Sawmill Rough Product %	0	100.0	0	

Hour Statistics

Species: Doug Fir

Wood Density ft^3/BDU	85.40	
Bark Density ft^3/BDU	77.40	
Hours Per Day	19.40	
Hours Per Month	404.25	
Hours Per Year	1229.74	Assumes entire mill is operated on just this species.

Table 6-4 - Woodwaste Availability, Lignum Ltd.

Recovery per m^3 debarked logs

Species: spf

	ft^3/m^3	Percent Cubic	Recovery Per CM
Net Lumber	12.3	34.9	
Green Chips	16.1	45.7	0.168
Dry Chips	0.9	2.6	0.010
Sawdust	3.9	11.0	0.040
Shavings	1.3	3.7	0.014
Mix Shrinkage	0.8	2.2	
Total Cubic	35.3	100.0	
Bark	2.7	7.5	0.036
Rough Lumber	15.3	43.29	0.238

Material Flow Report

Species: spf

	Recovery	Unit Label	Volume /Hour	Volume /Day	Volume /Month	Volume /Year
Hours Oprn				19	404	3057
Net Lumber		MBF				
Green Chips	0.168	BDU	31.5	611	12736	96319
Dry Chips	0.010	BDU	1.9	36	758	5733
Sawdust	0.040	BDU	7.5	146	3032	22933
Shavings	0.014	BDU	2.6	51	1061	8027
Bark	0.036	BDU	6.81	131	2729	20640
Logs	1.000	CM	187.5	3639	75807	543330
CF/CM	35.300	CCF	66.2	1284	26760	202385

Key Assumptions

Species: spf

	Sold Rough Grn	Sold S4S Grn	Sold SRS Dry	Weighted Average
Percent Volume Sold	0	0	100.0	
Adjusted % Volume Sold	0	0	100.0	
Prod Sawn Size Of CF/MBF	0	0	64.3	64.30
Percent Vol Shrinkage	0	0	5.0	5.00
Percent Planer Trim	0	0	7.0	7.00
Sold Size Avg CF/MBF	67.1	61.7	58.3	55.60
Sawmill Rgh Product %	0	0	100.0	

Hour Statistics

Species: spf

Wood Density CF/BDU	96.00	
Bark Density CF/BDU	77.10	
Hours Per Day	19.40	
Hours Per Month	404.25	
Hours Per Year	3057.34	Assumes entire mill is operated on just this species.

Table 6-5 - Woodwaste Availability, Lignum Ltd.

Recovery per m^3 debarked logs

Species: Doug Fir

	Units	ft^3/m^3	Percent Recovery Cubic	Per CM
Net Lumber	MBF	20.2	57.3	
Green Chips	BDU	11.9	33.6	0.139
Dry Chips	BDU			
Sawdust	BDU	2.8	8.0	0.033
Shavings	BDU	0.4	1.1	0.005
Mix Shrinkage				
Total Cubic		20.9	100.0	
Bark	BDU	6.7	18.9	0.086
Rough Lumber	MBF	20.9	59.21	0.234
Logs	CM	35.3	100.00	

Material Flow Report

Species: Doug Fir

	Recovery	Unit Label	Volume /Hour	Volume /Day	Volume /Month	Volume /Year
Hours Oprn				16	320	523
Net Lumber		MBF				
Green Chips	0.139	BDU	1.85	29	573	936
Dry Chips	0	BDU	0	0	0	0
Sawdust	0.033	BDU	0.4	7	136	222
Shavings	00.05	BDU	0.1	1	21	34
Bark	0.086	BDU	1.1	18	355	579
Logs	1.000	CM	12.9	206	4123	6733
CF/CM	35.300	CCF	4.5	73	1455	2377

Key Assumptions

Species: Doug Fir

	Sold Rough Grn	Sold S4S Grn	Sold SRS Dry	Weighted Average
Percent Volume Sold	80.0	20.0	0	
Adjusted % Volume Sold	80.0	20.0	0	
Prod Sawn Size Of CF/MBF	86.6	91.1	0	89.13
Percent Vol Shrinkage	0	0	0	
Percent Planer Trim	0	7.0	0	1.48
Sold Size Avg CF/MBF	88.6	83.3	0	87.54
Sawmill Rgh Product %	78.8	21.2	0	

Hour Statistics

Species: Doug Fir

Wood Density CF/BDU	85.40	
Bark Density CF/BDU	77.40	
Hours Per Day	16.00	
Hours Per Month	320.00	
Hours Per Year	522.59	Assumes entire mill is operated on just this species.

Table 6-6 - Woodwaste Availability, Lignum Ltd.

Recovery per m^3 debarked logs

Species: spf

	Units	ft^3/m^3	Percent Cubic	Recovery Per CM
Net Lumber	MBF	19.8	56.0	
Green Chips	BDU	12.3	34.9	0.127
Dry Chips	BDU			
Sawdust	BDU	2.8	8.0	0.029
Shavings	BDU	0.4	1.1	0.004
Mix Shrinkage				
Total Cubic		35.3	100.0	
Bark	BDU	3.4	9.7	0.045
Rough Lumber	MBF	20.5	57.93	0.229
Logs	CM	35.3	100.00	

Material Flow Report

Species: spf

	Recovery	Unit Label	Volume /Hour	Volume /Day	Volume /Month	Volume /Year
Hours Oprn				16	320	4843
Net Lumber		MBF				
Green Chips	0.127	BDU	1.7	27	555	8268
Dry Chips	0	BDU	0	0	0	0
Sawdust	0.029	BDU	0.4	6	122	1888
Shavings	0.004	BDU	0.1	1	17	260
Bark	0.045	BDU	0.6	9	190	2930
Logs	1.000	CM	13.2	211	4214	65100
CF/CM	35.300	CCF	4.6	74	1488	22980

Key Assumptions

Species: spf

	Sold Rough Grn	Sold S4S Grn	Sold SRS Dry	Weighted Average
Percent Volume Sold	80.0	20.0	0	
Adjusted % Volume Sold	80.0	20.0	0	
Prod Sawn Size Of CF/MBF	88.6	91.1	0	89.13
Percent Vol Shrinkage	0	0	0	
Percent Planer Trim	0	7.0	0	1.48
Sold Size Avg CF/MBF	88.6	83.3	0	87.54
Sawmill Rgh Product %	78.8	21.2	0	

Hour Statistics

Species: spf

Wood Density CF/BDU	97.20	
Bark Density CF/BDU	75.60	
Hours Per Day	16.00	
Hours Per Month	320.00	
Hours Per Year	4943.43	Assumes entire mill is operated on just this species.

Table 6-7 - Woodwaste Availability, Lignum Ltd.

Recovery per m^3 debarked logs

Species: Doug Fir

	Units	ft^3/m^3	Percent Recovery Cubic	Per CM
Net Lumber	MBF	13.1	37.0	
Green Chips	BDU	17.2	48.7	0.201
Dry Chips	BDU			
Sawdust	BDU	2.8	8.0	0.033
Shavings	BDU	2.2	6.2	0.033
Mix Shrinkage				
Total Cubic		35.3	100.0	
Bark	BDU	6.7	18.9	0.086
Rough Lumber	MBF	17.1	48.30	0.245
Logs	CM	35.3	100.00	

Material Flow Report

Species: Doug Fir

	Recovery	Unit Label	Volume /Hour	Volume /Day	Volume /Month	Volume /Year
Hours Oprn						
Net Lumber		MBF				
Green Chips	0.201	BDU	20.5	465	9771	19402
Dry Chips	0	BDU	0	0	0	0
Sawdust	0.033	BDU	3.4	76	1604	3185
Shavings	0.026	BDU	2.7	60	1264	2510
Bark	0.086	BDU	8.8	199	4181	8301
Logs	1.000	CM	102.0	2315	48611	96525
CF/CM	35.300	CCF	36.0	817	17160	34073

Key Assumptions

Species: Doug Fir

	Sold Rough Grn	Sold S4S Grn	Sold SRS Dry	Weighted Average
Percent Volume Sold	0	100.0	0	
Adjusted % Volume Sold	0	100.0	0	
Prod Sawn Size Of CF/MBF	0	69.5	0	69.50
Percent Vol Shrinkage	0	0	0	
Percent Planer Trim	0	12.0	0	12.00
Sold Size Avg CF/MBF	0	60.5	0	60.50
Sawmill Rgh Product %	0	100.0	0	

Hour Statistics

Species: Doug Fir

Wood Density CF/BDU	85.40	
Bark Density CF/BDU	77.40	
Hours Per Day	22.70	
Hours Per Month	476.70	
Hours Per Year	946.57	Assumes entire mill is operated on just this species.

Table 6-8 - Woodwaste Availability, Lignum Ltd.

Recovery per m^3 debarked logs

Species: spf

	Units	ft^3/m^3	Percent Cubic	Recovery Per CM
Net Lumber	MBF	12.1	34.2	
Green Chips	BDU	15.6	44.1	0.182
Dry Chips	BDU	1.6	4.7	0.019
Sawdust	BDU	2.8	8.0	0.033
Shavings	BDU	1.7	4.7	0.020
Mix Shrinkage		1.5	4.3	
Total Cubic		35.3	100.0	
Bark	BDU	2.7	7.5	0.034
Rough Lumber	MBF	16.9	47.90	0.245
Logs	CM	35.3	100.00	

Material Flow Report

Species: spf

	Recovery	Unit Label	Volume /Hour	Volume /Day	Volume /Month	Volume /Year
Hours Oprn				23	477	5364
Net Lumber		MBF				
Green Chips	0.182	BDU	18.6	421	8847	99549
Dry Chips	0.019	BDU	1.9	44	924	10393
Sawdust	0.033	BDU	3.4	76	1604	18050
Shavings	0.020	BDU	2.0	46	972	10939
Bark		BDU				
Logs	1.000	CM	102.0	2315	48611	546975
CF/CM	35.300	CCF	36.0	817	17160	193082

Key Assumptions

Species: spf

	Sold Rough Grn	Sold S4S Grn	Sold SRS Dry	Weighted Average
Percent Volume Sold	0	0	100.0	
Adjusted % Volume Sold	0	0	100.0	
Prod Sawn Size Of CF/MBF	0	0	68.9	68.90
Percent Vol Shrinkage	0	0	9.0	9.00
Percent Planer Trim	0	0	12.0	12.00
Sold Size Avg CF/MBF	0	0	55.9	55.90
Sawmill RGH Product %	0	0	100.0	

Hour Statistics

Species: spf

Wood Density CF/BDU	85.40	
Bark Density CF/BDU	77.40	
Hours Per Day	22.70	
Hours Per Month	476.70	
Hours Per Year	5363.87	Assumes entire mill is operated on just this species.

Table 6-9 - Woodwaste Availability, Lignum Ltd.

Recovery per m^3 debarked logs

Species: Cedar

	Units	ft^3/m^3	Percent Cubic	Recovery Per CM
Net Lumber	MBF	11.1	31.3	
Green Chips	BDU	17.7	50.1	0.151
Dry Chips	BDU	0.7	1.9	0.006
Sawdust	BDU	2.8	8.0	0.024
Shavings	BDU	2.0	5.7	0.017
Mix Shrinkage		1.1	3.1	
Total Cubic		35.3	100.0	
Bark	BDU	4.8	13.7	0.042
Rough Lumber	MBF	15.0	42.35	0.180
Logs	CM	35.3	100.00	

Material Flow Report

Species: Cedar

	Recovery	Unit Label	Volume /Hour	Volume /Day	Volume /Month	Volume /Year
Hours Oprn				16	336	1042
Net Lumber		MBF				
Green Chips	0.151	BDU	9.0	145	3038	9418
Dry Chips	0.006	BDU	0.4	6	121	374
Sawdust	0.024	BDU	1.4	23	483	1497
Shavings	0.017	BDU	1.0	16	342	1060
Bark	0.042	BDU	2.5	40	845	2620
Logs	1.000	CM	59.9	958	20120	62370
CF/CM	35.300	CCF	21.1	338	7102	22017

Key Assumptions

Species: Cedar

	Sold Rough Grn	Sold S4S Grn	Sold SRS Dry	Weighted Average
Percent Volume Sold	0	20.0	80.0	
Adjusted % Volume Sold	0	20.0	80.0	
Prod Sawn Size Of CF/MBF	0	83.3	83.3	83.30
Percent Vol Shrinkage	0	0	9.0	7.20
Percent Planer Trim	0	7.0	7.0	7.00
Sold Size Avg CF/MBF	0	70.8	65.0	77.16
Sawmill RGH Product %	0	20.0	80.0	

Hour Statistics

Species: Cedar

Wood Density CF/BDU	117.10	
Bark Density CF/BDU	114.30	
Hours Per Day	16.00	
Hours Per Month	336.00	
Hours Per Year	1041.58	Assumes entire mill is operated on just this species.

Table 6-10 - Woodwaste Availability, Lignum Ltd.

Recovery per m^3 debarked logs

Species: Doug Fir

	Units	ft^3/m^3	Percent Recovery Cubic	Per CM
Net Lumber	MBF	13.4	38.0	
Green Chips	BDU	17.3	48.9	0.202
Dry Chips	BDU			
Sawdust	BDU	2.8	8.0	0.033
Shavings	BDU	1.8	5.1	0.021
Mix Shrinkage				
Total Cubic		35.3	100.0	
Bark	BDU	6.7	18.9	0.086
Rough Lumber	MBF	15.2	43.12	0.232
Logs	CM	35.3	100.00	

Material Flow Report

Species: Doug Fir

	Recovery	Unit Label	Volume /Hour	Volume /Day	Volume /Month	Volume /Year
Hours Oprn				20	568	1510
Net Lumber		MBF				
Green Chips	0.202	BDU	23.5	470	13349	35507
Dry Chips	0	BDU	0	0	0	0
Sawdust	0.033	BDU	3.8	77	2181	5801
Shavings	0.021	BDU	2.4	49	1388	3691
Bark	0.086	BDU	10.0	200	5683	15117
Logs	1.000	CM	116.4	2328	66083	175779
CF/CM	35.300	CCF	41.1	822	23327	62050

Key Assumptions

Species: Doug Fir

	Sold Rough Grn	Sold S4S Grn	Sold SRS Dry	Weighted Average
Percent Volume Sold	0	100.0	0	
Adjusted % Volume Sold	0	100.0	0	
PROD SAWN SIZE OF CF/MBF	0	65.6	0	65.60
Percent Vol Shrinkage	0	0	0	
Percent Planer Trim	0		0	
Sold Size Avg CF/MBF	0	57.8	0	57.80
Sawmill RGH Product %	0	100.0	0	

Hour Statistics

Species: Doug Fir

Wood Density CF/BDU	85.40	
Bark Density CF/BDU	77.40	
Hours Per Day	20.00	
Hours Per Month	567.83	
Hours Per Year	1510.40	Assumes entire mill is operated on just this species.

Table 6-11 - Woodwaste Availability, Lignum Ltd.

Recovery per m^3 debarked logs

Species: spf

	Units	ft^3/m^3	Percent Cubic	Recovery Per CM
Net Lumber	MBF	14.5	41.1	
Green Chips	BDU	15.0	42.6	0.159
Dry Chips	BDU			
Sawdust	BDU	2.8	8.0	0.033
Shavings	BDU	1.4	3.8	0.014
Mix Shrinkage		1.6	4.4	
Total Cubic		35.3	100.0	
Bark	BDU	2.5	7.2	0.035
Rough Lumber	MBF	17.5	49.43	0.266
Logs	CM	35.3	100.00	

Material Flow Report

Species: spf

	Recovery	Unit Label	Volume /Hour	Volume /Day	Volume /Month	Volume /Year
Hours Oprn				17	336	3231
Net Lumber		MBF				
Green Chips	0.159	BDU	30.6	490	10283	98898
Dry Chips	0	BDU	0	0	0	0
Sawdust	0.030	BDU	5.8	92	1940	18660
Shavings	0.014	BDU	2.7	43	905	8708
Bark	0.035	BDU	6.7	108	2264	21770
Logs	1.000	CM	192.5	3080	64676	622000
CF/CM	35.300	CCF	67.9	1087	22831	219566

Key Assumptions

Species: spf

	Sold Rough Grn	Sold S4S Grn	Sold SRS Dry	Weighted Average
Percent Volume Sold	0	0	100.0	
Adjusted % Volume Sold	0	0	100.0	
Prod Sawn Size Of CF/MBF	0	0	65.6	65.60
Percent Vol Shrinkage	0	0	9.0	9.00
Percent Planer Trim	0	0	0	
Sold Size Avg CF/MBF	0	0	54.6	54.60
Sawmill RGH Product %	0	0	100.0	

Hour Statistics

Species: spf

WOOD DENSITY CF/BDU		
BARK DENSITY CF/BDU	73.40	
HOURS PER DAY	16.00	
HOURS PER MONTH	336.00	
Hours Per Year	3231.37	Assumes entire mill is operated on just this species.

Table 6-12 - Woodwaste Availability, Lignum Ltd.

Recovery per m^3 debarked logs

Species: Doug Fir

	Units	ft^3/m^3	Percent Cubic	Recovery Per CM
Net Lumber	MBF	14.4	40.8	
Green Chips	BDU	16.4	46.4	0.192
Dry Chips	BDU			
Sawdust	BDU	2.8	8.0	0.033
Shavings	BDU	1.7	4.7	0.020
Mix Shrinkage				
Total Cubic		35.3	100.0	
Bark	BDU	6.7	18.9	0.086
Rough Lumber	MBF	16.9	47.73	0.250
Logs	CM	35.3	100.00	

Material Flow Report

Species: Doug Fir

	Recovery	Unit Label	Volume /Hour	Volume /Day	Volume /Month	Volume /Year
Hours Oprn				16	336	959
Net Lumber		MBF				
Green Chips	0.192	BDU	19.2	308	6465	18457
Dry Chips	0	BDU	0	0	0	0
Sawdust	0.030	BDU	3.3	53	1111	3172
Shavings	0.020	BDU	2.0	32	683	1923
Bark	0.086	BDU	8.6	138	2896	8267
Logs	1.000	CM	100.2	1603	33671	96128
CF/CM	35.300	CCF	35.4	566	11886	33933

Key Assumptions

Species: Doug Fir

	Sold Rough Grn	Sold S4S Grn	Sold SRS Dry	Weighted Average
Percent Volume Sold	0	100.0	0	
Adjusted % Volume Sold	0	100.0	0	
Prod Sawn Size Of CF/MBF	0	67.5	0	67.50
Percent Vol Shrinkage	0	0	0	
Percent Planer Trim	0	5.0	0	5.00
Sold Size Avg CF/MBF	0	60.8	0	60.80
Sawmill RGH Product %	0	100.0	0	

Hour Statistics

Species: Doug Fir

Wood Density CF/BDU	85.40	
Bark Density CF/BDU	77.40	
Hours Per Day	16.00	
Hours Per Month	336.00	
Hours Per Year	959.26	Assumes entire mill is operated on just this species.

Table 6-13 - Woodwaste Availability, Lignum Ltd.

Recovery per m^3 debarked logs

Species: spf

	Units	ft^3/m^3	Percent Cubic	Recovery Per CM
Net Lumber	MBF	1.35	38.3	
Green Chips	BDU	15.2	42.9	0.152
Dry Chips	BDU	1.1	3.2	0.011
Sawdust	BDU	2.8	8.0	0.028
Shavings	BDU	1.2	3.4	0.012
Mix Shrinkage		1.5	4.2	
Total Cubic		35.3	100.0	
Bark	BDU	3.0	8.49	0.039
Rough Lumber	MBF	17.4	49.18	0.257
Logs	CM	35.3	100.00	

Material Flow Report

Species: spf

	Recovery	Unit Label	Volume /Hour	Volume /Day	Volume /Month	Volume /Year
Hours Oprn				16	336	2999
Net Lumber		MBF				
Green Chips	0.152	BDU	35.0	559	11744	104841
Dry Chips	0.011	BDU	2.5	40	850	7587
Sawdust	0.028	BDU	6.4	103	2163	19313
Shavings	0.012	BDU	2.8	44	927	8277
Bark	0.039	BDU	9.0	143	3013	26900
Logs	1.000	CM	230.0	3679	77266	689744
CF/CM	35.300	CCF	81.2	1299	27275	243480

Key Assumptions

Species: spf

	Sold Rough Grn	Sold S4S Grn	Sold SRS Dry	Weighted Average
Percent Volume Sold	0	4.0	96.0	
Adjusted % Volume Sold	0	4.0	96.0	
Prod Sawn Size Of CF/MBF	0	67.5	67.5	67.50
Percent Vol Shrinkage	0	0	9.0	8.65
Percent Planer Trim	0	5.0	8.0	7.88
Sold Size Avg CF/MBF	0	60.8	56.9	57.06
Sawmill RGH Product %	0	3.9	96.1	

Hour Statistics

Species: spf

Wood Density CF/BDU	99.50	
Bark Density CF/BDU	76.90	
Hours Per Day	16.00	
Hours Per Month	336.00	
Hours Per Year	2999.44	Assumes entire mill is operated on just this species.

Table 6-14 - Woodwaste Availability, Lignum Ltd.

Recovery per m^3 debarked logs

Species: Cedar

	Units	ft^3/m^3	Percent Cubic	Recovery Per CM
Net Lumber	MBF	13.5	38.3	
Green Chips	BDU	15.2	42.9	0.152
Dry Chips	BDU	1.1	3.2	0.011
Sawdust	BDU	2.8	8.0	0.028
Shavings	BDU	1.2	3.4	0.012
Mix Shrinkage		1.5	4.2	
Total Cubic		35.3	100.0	
Bark	BDU	4.8	13.7	0.063
Rough Lumber	MBF	17.4	49.18	0.257
Logs	CM	35.3	100.00	

Material Flow Report

Species: Cedar

	Recovery	Unit Label	Volume /Hour	Volume /Day	Volume /Month	Volume /Year
Hours Oprn				16	336	69
Net Lumber		MBF				
Green Chips	0.152	BDU	35.0	559	11744	2410
Dry Chips	0.011	BDU	2.5	40	850	174
Sawdust	0.028	BDU	6.4	103	2163	444
Shavings	0.012	BDU	2.8	44	927	190
Bark	0.063	BDU	14.5	232	4868	999
Logs	1.000	CM	230.0	3679	77266	15956
CF/CM	35.300	CCF	81.2	1299	27275	5597

Key Assumptions

Species: Cedar

	Sold Rough Grn	Sold S4S Grn	Sold SRS Dry	Weighted Average
Percent Volume Sold	0	4.0	96.0	
Adjusted % Volume Sold	0	4.0	96.0	
Prod Sawn Size Of CF/MBF	0	67.5	67.5	67.50
Percent Vol Shrinkage	0	0	9.0	8.65
Percent Planer Trim	0	5.0	8.0	7.88
Sold Size Avg CF/MBF	0	60.8	56.9	57.06
Sawmill Rgh Product %	0	3.9	96.1	

Hour Statistics

Species: Cedar

Wood Density CF/BDU	99.50	
Bark Density CF/BDU	76.90	
Hours Per Day	16.00	
Hours Per Month	336.00	
Hours Per Year	68.95	Assumes entire mill is operated on just this species.

Table 6 - 15 Williams Lake Cogeneration Study

Woodwaste Characteristics - By Species

	Units	DFir	LPP	SPR	S-A Fir	CED
Bark Moisture Content	%	45.0	35.0	43.0	43.0	45.0
Chip & Debris Moisture	%	43.0	39.0	39.0	39.0	45.0
Sawdust Moisture Content	%	43.0	39.0	39.0	39.0	45.0
Shavings Moisture Content	%	43.0	15.0	15.0	15.0	45.0
Wood Density	#/CF (1)	28.1	25.5	22.2	20.9	20.5
Wood Density	#/CM (1)	992	900	784	738	724
Bark Density	#/CF (1)	31	33	28	31	21
Bark Density	#/CM (1)	1094	1165	988	1094	741
Wood Density	CF/BDU	85.4	94.1	108.1	114.8	117.1
Bark Density	CF/BDU	77.4	72.7	87.7	77.4	114.3
Higher Heating Value Bark		10100	10760	8800	9000	8700
Higher Heating Value Wood		9200	8600	8500	8616	9700
Bark % roundwood on mill deck		18.9%	7.1%	10.7%	10.6%	13.7%

Table 6-16 Mill Woodwaste Factors

		Lignum	Jacob Brs	Weldwood	P & T	W Fraser	Jackpine
Log Yard Debris Percent of Log Volume	%	1.5	0.8	0.0	1.0	1.0	1.0
Mill Deck Lily Pad Vol % SPF	%	1.5	0.2	0.0	0.3	0.0	1.0
Mill Deck Lily Pad Vol % Doug Fir	%	1.5	0.2	0.0	0.3	0.0	1.0
Percent of fines removed from chips	%	1.5	1.5	0.0	1.5	1.5	1.5

Table 6-17 - Summary of Woodwaste Heating Value

Species: Douglas Fir	Units	Lignum	Jacob Brs	Weldwood	P & T	W Fraser	Jack Pine
				Douglas Fir			
Gross Log Volume	CM	207623	97000	80000	178000	97500	6733
Log Yard Debriss	CM	3114	728	0	1780	975	67
Lily Pad Volumee	CM	3068	144	0	441	0	67
Net Log Volume to Mill	CM	201441	96128	80000	175779	96525	6599
Yard Debris + Lily Pad	BDU	2555	360	0	918	403	55
Sawdust & Chip Fines	BDU	9065	3036	0	5801	3185	222
Shavings	BDU	2820	1840	0	3691	2510	34
Bark	BDU	17897	8361	6896	15343	8404	580
Tot Residue (no chips)	BDU	32337	13598	6896	25753	14502	892
Average MC Doug Fir	%	44.1	44.2	45.0	44.2	44.2	44.3
				Spruce - Pine - Fir			
Gross Log Volume	CM	590925	696000	720000	622000	552500	65114
Log Yard Debris	CM	8864	5220	0	6220	5525	651
Lily Pad Volume	CM	8731	1036	0	1539	0	645
Net Log Volume to Mill	CM	573330	689744	720000	614241	546975	63818
Log Vol: Spruce	CM	55898	210000	240000	32000	32500	14467
Log Vol: S-A Fir	CM	15971	41000	80000	0	32500	0
Percent LP	%	87.8	63.9	55.6	94.9	88.2	77.8
Percent Spruce	%	9.5	30.2	33.3	5.1	5.9	22.2
Percent S-A Fir	%	2.7	5.9	11.1	0.0	5.9	0.0
Debris + Lily Pad	BDU	6486	2230	0	2891	2034	472
Sawdust & Chip Fines	BDU	22933	18564	0	18660	18050	1888
Shavings	BDU	8027	7956	0	8708	10939	260
Bark + LY Debris & LP	BDU	21130	26579	28235	21750	19810	2384
Bark Vol: LPP	CM	36853	31595	28400	41890	34613	3596
Bark Vol: Spruce	CM	5981	22470	25680	3424	3478	1548
Bark Vol: S-A Fir	CM	1693	4346	8480	0	3445	0
Tot Residue (no chips)	BDU	58576	55329	28235	52009	50833	5004
Average SPF % Bark	%	7.5	8.4	8.7	7.3	7.5	7.9
Avg. Wood Density	CF/BDU	96.0	99.5	101.1	94.8	96.1	97.2
Avg. Bark Density	CF/BDU	74.6	78.1	78.7	73.7	74.2	76.6
MC Chips & Debris	%	39.0	39.0	39.0	39.0	39.0	39.0
MC Sawdust	%	39.0	39.0	39.0	39.0	39.0	39.0
MC Shavings	%	15.0	15.0	15.0	15.0	15.0	15.0
MC Bark	%	36.4	38.7	39.4	35.6	36.3	37.4
Avg. MC SPF	%	35.5	36.2	39.4	34.5	33.9	37.3
Avg. As-fired Wood	BTU/LB	8591	8571	8568	8595	8595	8578
Avg. As-fired Bark	BTU/LB	10415	9846	9665	10612	10418	10170

Table 6-18 - Cedar Woodwaste Contribution - Mill

	Units	Lignum	Jacob Brs	Weldwood	P & T	W. Fraser	Jack Pine
Species: Western Red Cedar							
Gross Log Volume	CM		16000			63000	0
Log Yard Debris	CM	0	120	0	0	630	0
Lily Pad Volume	CM	0	24	0	0	0	0
Net Log Volume to Mi	CM	0	15856	0	0	62370	0
Yard Debris + Lily Pad	BDU	0	43	0	0	190	0
Chips Produced	BDU	0	2584	0	0	9792	0
Sawdust & Chip Fines	BDU	0	444	0	0	1497	0
Shavings	BDU	0	190	0	0	1060	0
Bark	BDU	0	677	0	0	2666	0
Total Residue	BDU	0	1354	0	0	15205	0
Avg. MC Cedar (chips WFraser only)	%		45.0			45.0	

Don Baack and Associates Tables

APPENDIX 7

SITE SELECTION

REPORT X7801/1
CARIBOO WOODWASTE STUDY

MINISTER OF STATE
CARIBOO DEVELOPMENT REGION
VICTORIA BRITISH COLUMBIA

DATE 9 MARCH 1989

APPENDIX 7 - SITE SELECTION

INTRODUCTION

Sandwell staff visited Williams Lake and identified three potential power plant sites. These sites have been evaluated with regard to the major requirements for a suitable site, the requirements include: land availability and accessibility, fuel transport, water supply and effluent disposal, proximity to the existing power transmission system, zoning, adjacent land uses, environmental protection and potential aesthetic impact. However, no detailed environmental assessment was conducted for the potential sites identified in this report.

This appendix outlines the evaluation of the three potential sites and recommends a preferred site for the proposed woodwaste power plant.

PROPOSED POWER PLANT DEVELOPMENT

General

The proposed thermal power plant development is designed to use the projected hog fuel surplus in the Williams Lake area. The review of fuel quality and availability, indicates that a 60 MW power plant could utilize the volume of woodwaste available from the local Williams Lake area. If virtually all woodwaste from the southern Cariboo region is to be burnt, the hog fuel available could sustain a 140 MW power plant. However, transportation costs of the relatively low grade fuel and future reduction of the white wood portion of woodwaste makes the larger plant concept impractical. For this site selection study, a site suitable for a nominal 60 MW power plant, with some room for expansion, has been considered.

Description

The power plant consists of two principal structures, the power house containing boilers and turbines and the fuel handling, storage and recovery equipment. The plant and structures are described in more detail in the body of the report and in Appendix 8. Auxiliary structures include a cooling tower, precipitator, stack and power sub-station.

The major structures appear as a steel rectangular industrial building 36 m (about 8 stories) high which enclose the boilers, turbine generators, condenser and controls for the facility. Associated components to the powerhouse are; the electrostatic precipitator which abuts the plant as a building (about half the powerhouse height) and the stack which will be not less than 60 metres.

The fuel storage area is similar in most aspects to chip storage piles found at most pulp mills. The storage pile height will reach up to 10 m and will vary over the year according to supply and consumption.

A small, 10 m x 10 m, switching facility will connect the generator output to the B.C. Hydro 60 kVa transmission line. The line from the plant to the sub-station will be similar to the present one providing B.C. Hydro power to the Williams Lake city sub-station.

Previous studies for similar sized woodwaste fired power plants at Quesnel and other locations, found that a "once-through" river water cooling system was not an environmentally and economically acceptable option. A once-through system for a 60 MW plant would require up to 4 m^3/s of cooling water. For this study it has been assumed that cooling towers would be used for waste heat disposal. A site close to a major body of water would not be required.

SITE REQUIREMENTS

Site Area

The site area should accommodate a 60 MW power plant, with adequate expansion for additional fuel storage should woodwaste have to be hauled from distances beyond Quesnel. As haul distance increases, a larger fuel reserve is required to allow for potential supply interception.

A major portion of the site would be used for woodwaste storage as sawmills have little or no on-site storage areas for woodwaste. To allow for continuous power plant operation and for accumulation of woodwaste when the power plant is not operating, an area sufficient to store up to two month's supply of woodwaste is considered adequate. A 60 MW plant would require about 7 ha for woodwaste storage. For a potentially larger plant a fuel storage area of about 10 ha would be adequate.

The 60 MW power plant building, switchyard and chimney would occupy about 2 ha. Additional space would be required to allow adequate truck and possibly rail access, fuel loading and conveying to storage, cooling towers and ash handling and storage areas.

A 60 MW plant would require about 8-10 ha of land area. On-site disposal of boiler ash and fly ash to landfill would double these land requirements, however, this is unlikely to be a viable option where adjacent land will have a potentially higher value as industrial land. Depending on the site location, additional land to provide areas for buffer zones may be desirable. Tentative plans would include seedling greenhouses and nurseries as the principal buffer.

Site Location

The proposed 60 MW power plant would use woodwaste from the sawmills in Williams Lake with a posssible truck hauled supplement from mills in Lac La Hache, 100 Mile House and Quesnel. Power would be supplied to the B.C. Hydro power transmission system through the local Williams Lake sub-station and steam or hot water could be supplied to the local sawmills. Low grade heat would be also available to other nearby commercial operations. Thus a power plant site close to the sawmills would minimize woodwaste transport and handling distances and the length of pipelines required to convey steam, hot water or thermal oil.
A plant site location within the limits of Williams Lake would facilitate access to municipal resources, such as water supply, fire fighting and effluent treatment and disposal systems.

To minimize the potential adverse effects of dust and atmospheric emissions it would be desirable to locate the power plant downwind of the city and as far away as practical from residential and commercial areas. The winds at Williams Lake are influenced by the valley topography and move in a predominantly southeast-northwest direction. Southerly winds predominate, being twice as frequent as winds from the north. Thus emissions from a plant site located to the north of the city centre would impact less frequently on the urban centre.

There is no baseline data on wind and temperature for the city, Williams Lake airport being the nearest source of long term meteorological records. As the city is located in a valley a variety of micro wind and temperature variations probably occur over the course of a year. This base data collection should be started as soon as possible to permit realistic evaluation of stack emissions dispersion for locations within and beyond the city.

Physical Conditions

The site shall be relatively level, well above river flood levels, free from unstable ground or danger of landslides and made up of subsoils suitable to accept large concentrated loads without undue additional costs for foundations.

Access

Good road access is considered important for delivery of woodwastes. The woodwastes may originate from neighboring sawmills or from more remote locations to the north and south of the city. Adequate road access would also be required during construction.

Potential rail access is desirable to allow the possible delivery of woodwaste fuel by rail from more distant areas. Nearby access would also be convenient for construction of the plant.

Water Supply

The power plant would require process water for makeup in the boiler steam/condensate system and in the cooling tower system. For a 60 MW plant with a wet type cooling tower, evaporation and drift losses would be about 36 L/s and blowdown would average about 27 L/s. Boiler blowdown would average just over 1.2 L/S.

The domestic water requirement would be small, about 0.5 L/s. The total peak water requirement for a 60 MW plant would be about 45 L/s.

Heat Distribution and Conveyorized Woodwaste

A plant location as close as practical to the largest group of mills is desirable for two reasons. The power plant could provide heat for use in the lumber drying kiln at the adjacent sawmills. A site location which minimizes the length of pressurized distribution and return pipelines would be advantageous.

The transport of woodwaste from the nearby mills by conveyors is also a practical alternative to trucking.

Power Transmission

A suitable switchyard and a 60 kV transmission line would be required to connect to the B.C. Hydro power grid at the substation in Williams Lake. A transmission line route through part of the town would be necessary for overhead power lines. The existing B.C. Hydro substation is located in the south part of the town near Boitanio Park. The transmission line would be similar to the existing B.C. Hydro supply along MacKenzie Avenue and Comer Street and could parallel the existing B.C. Hydro line.

Ash Disposal

A conventional 60 MW woodwaste-fired power plant would produce about 5,000 to 8,000 tonnes of ash per year which would have to be disposed of to a suitable landfill site. This does not include char, which will be removed and reinjected into the boiler. For longterm ash disposal a total land area of about 8-10 ha should be considered. City landfill areas will be sufficient for several years at ash volumes of 5000-6000 tonnes.

Natural Gas Supply

An alternative source of fuel would be required for start-up and to enable the power plant to operate at full capacity during short periods when the woodwaste supply to the boiler is interrupted. For full load operation, a natural gas supply of 6 m^3/s would be required for a 60 MW plant.

Municipal Services

Other services required, which could be provided by the municipality, would include a standby water supply for fire fighting. The fire water requirement would be about 50 l/s. Effluent treatment of blowdown from cooling water and boiler water systems is not required.

POTENTIAL PLANT SITES

General

The city of Williams Lake is situated at the end of Williams Lake in a well defined valley, which is oriented in a northwest-southeast direction, Figure 1. The city centre lies at an elevation of about 600 m. The surrounding hills rise to about 950 m. The Fraser River, which lies about 9 km west of the city, flows in a deeper, narrower valley oriented in a north-south direction. This rugged topography limits the availability of attractive sites for a power plant development.

Three general regions where the proposed power plant site could be located have been identified: outside of the city on the high ground to the southwest or to the northeast of the city centre; at the south end of the city in the vicinity of the two large sawmills along Highway No. 20; and at the north end of the city near three sawmills and wood processing plants located in that area.

The areas outside of the city are not considered to be appropriate for several reasons: longer haul distances, 10 to 15 km, for woodwastes, more costly water supply and effluent disposal systems would be required, natural gas would not be readily available,

municipal services would not be available, and waste heat utilization would not be possible as there would be no nearby users of steam or hot water.
The area at the south end of the city is considered to be less desirable than the area to the north. The major portion of the woodwaste fuel, almost 60 percent, would come from the sawmills to the north of the city, thus transport costs to a site in the south of the city would be greater. The area around the two sawmills in the south part of the city is largely residential, commercial and recreational, and there are limited areas for a large industrial development. A power plant development in this area would be closer to prime residential and recreational areas, including the golf course and the lake.

Prevailing winds in Williams Lake are from the southeast. Atmospheric emissions from a plant in the south part of the city would be carried through the city by the prevailing winds according to existing wind data. No dispersion studies were conducted within the scope of this report.

The most convenient area for the proposed thermal power plant development is to the north of the city centre near the existing sawmills. This is a planned industrial area and there are several attractive industrial sites available. British Columbia Railway (BCR) has a large area of land close to the existing sawmills which is presently designated as agricultural land reserve (ALR).

The City of Williams Lake and B.C. Rail are presently applying to have this land reclassified and rezoned for industrial use. This process of removal from ALR, change of the Official Community Plan and rezoning is expected to take 4 to 6 months. The matter of lease versus freehold land title has not been addressed.

The city has recently approved improvements to the municipal water supply system in this area to the north of the centre of the city. Approximately $200,000 of additional work comprising increased pipe diameter and pump capacity should be added to the improvement program. Major roadway changes to improve access to this area and to bypass road traffic around the city centre are being planned by the city. This area is upwind of the city centre and nearby residential development is less intense compared to the southern part of the city. This area is close to the sources of the major portion of the woodwaste fuel supply and close to the main potential waste heat users.

The areas outside of Williams Lake and south of the city are considered to be less attractive for the proposed power plant development have not been evaluated further in this study. A potential site, subject to detailed environmental impact assessment, has been identified in the area north of the city. This is the site described in the following paragraph.

Site Location

The preferred location of the power plant is shown in Figure 3 of the report. Depending on site investigations, new road alignment and other factors the site could be reduced in size to the north and increased to the east.

The preferred location has been identified in cooperation with B.C. Rail Properties staff. It meets virtually all the established requirements set out in this document. The site is an area used under lease by the adjacent mills for log storage; however, B.C. Rail and the mill operators believe that an accommodation is possible. The site is gently sloping towards the mills and is located adjacent to two mills and is less than 500 metres from

the third mill. A proposed new arterial road will pass by the south end of the site. A rail spur to the Weldwood plant is about 250 metres from the south boundary.

The prospects for new adjacent co-generation applications is excellent as some 200 ha of industrial land is available immediately to the east of the proposed site.

The city water supply with minor improvements and sewer connections of adequate capacity are located approximately 1000 metres south of the site.

Surface drainage from the site, especially the woodwaste storage area, would be channeled, monitored and discharged into the natural drainage down slope past the sawmills and log storage areas. If the plant surface discharge expected to have damaging constituents or is unsightly, a site storage basin should be built to skim and settle drainage before it moves into natural drainage channels.

The impact of the plant stack plume is conjectural at this stage. Based upon Sandwell's experience with other power and steam plants a stack height of not less than 64 m is proposed for this location. Studies of the dispersion patterns expected at the site will be part of more detailed studies completed by project developers.

There is some potential for local effects from evaporation vapour from the cooling tower during cold weather conditions. In general, the relatively warmer condensation, as a vapour cloud, moves upward and disperses before coming in contact with the ground. Under some conditions the plume may not rise appreciably but instead disperse along the ground surface. For this reason the cooling tower should be located at a convenient distance away from access roads and truck dumping areas.

APPENDIX 8

POWER PLANT DETAILS

REPORT X7801/1
CARIBOO WOODWASTE STUDY

MINISTER OF STATE
CARIBOO DEVELOPMENT REGION
VICTORIA BRITISH COLUMBIA

DATE 9 MARCH 1989

APPENDIX 8 - POWER PLANT DETAILS

CONCEPTUAL DESIGN

The study has focussed on the design of a conventional hog-fuel-fired boiler and turbine generator system suitable for reliable economic production of electric power.

The best available current technology has been reviewed and is included where appropriate.

The system may provide process heat for nearby sawmill lumber dry kilns. Low-grade heat for condenser cooling water may be utilized for greenhouse heating.

Required emissions levels were provided by the Province of British Columbia Ministry of Environment. High-efficiency electrostatic precipitators would be provided for particulate emission control.

A survey of waste wood fuel was carried out and the future projections for hog fuel availability from the sawmills is 293,900 BDU/a or 2.02 Mm^3/a. The boiler has been specified to use all of this fuel. The boiler would be capable of delivering 61 kg/s (484,200 lb/h) high pressure steam to an extraction-condensing turbine at 11 MPag (1595 psig) and 510°C (950°F). These parameters have been selected with regard to plants of similar size, and contemporary turbine casing design pressures.

ASSUMPTIONS

The study was carried out on the following assumptions:

1. Hog Fuel Supply

   - The quantity of hog fuel available for the plant is 2.02 million m^3/a (293,900 BDU/a) from six designated sawmills in the Williams Lake area.

   - An appropriate hog fuel supply management system will be in place to regulate deliveries to the power plant.

2. External Heat Loads

   - Heat for kiln drying can be provided to the kilns operated by Pinette & Therien, West Fraser, Jackpine and Weldwood.

   - Costs for conversion of kiln heating equipment, or for greenhouse heating, would not form part of the station costs.

3. Site Conditions

- The geological and geotechnical foundation conditions and stability of the soil can be assessed with a satisfactory degree of reliability without soil tests and test drilling can be deferred until the project has been approved.

- The site selected from engineering aspects can be made available and costs assessed.

4. Environmental Aspects

- The station will be acceptable from an environmental point of view if it is designed to meet the environmental objectives stated in Appendix 11 as designated by the Ministry of Environment.

- The water vapour emitted by a cooling tower would not generally affect local fog conditions.

5. Operational Aspects

- The station is not essential to the BCHPA power supply system and can therefore be shut down without endangering the quality of supply to BCHPA's customers.

- The station must be capable of supplying power to the Williams Lake network if it becomes disconnected from the BCHPA transmission system. Additional synchronizing facilities may be required at the Williams Lake Substation to enable BCHPA to exploit this capability.

- Minor improvement in plant efficiency can be sacrificed in favour of lower initial plant capital cost and simplicity of operation.

- Normal operation of the plant would be on hog fuel. It is not anticipated that its operation would be maintained using standby fuel (gas) for more than very brief emergency periods.

- The station need not have "black start capability", i.e. the ability to start the system under its own power. Power can be imported from BCHPA.

- Where heat is provided to sawmills, service would be discontinued if the plant were shut down.

- The station would be locally controlled without control communication links to any of the central BCHPA control stations.

- Condenser cooling water can be supplied for greenhouse heating via piped systems.

6. Noise Levels

The plant would be designed and the equipment selected to meet the noise standards of the Worker's Compensation Board and, for specific equipment, to meet the noise level standard generally accepted within the industry for such equipment. The

objective would be to provide a noise level less than 85 dB (A). This level would obviate the need for hearing protection and hearing testing.

In instances where standard equipment would result in noise levels about 85 dB (A), special precautions would be taken. For example special hoods could be provided on motors. Valve and piping noise would be limited both by selection of suitable velocities and by judicious use of insulation.

CONCEPTUAL DESIGN

1. Site Description

Figures 2 and 3 show the location of the selected site and the important features surrounding it in the Williams Lake area. The process by which this site was selected is outlined in Appendix 7 "Site Selection".

2. Site Arrangement

Drawing 7801-461-03 shows the general arrangement of the thermal generating station. and Figure 3 shows the geographical location.

Site services would be required as follows:

a. Roads and Approach Areas

The roads would be paved except for the cooling tower access road. Asphalt pavement would be provided around the hog dump, and concrete pavement under and around the fly ash collectors, around the stack and in front of the garage.

b. Drainage

Site and road drainage would mainly be by open ditches to established water courses, as there is no municipal storm sewer nearby. An oil separator would be provided opposite the garage. Corrugated metal culverts would be provided in the ditches for road crossings, as required.

c. Domestic Effluent

The domestic effluent from washroom facilities at the hog fuel truck dump and at the power plant would be discharged into the City Sewer System.

d. Process Effluent

The greatest portion of the process effluent, which totals 9 L/s (80 GPM), would come from cooling tower blowdown. The rest would be waste from the boiler feedwater treatment plant. It is proposed to discharge this effluent into the municipal sewer. Estimates by city engineering staff indicate that this is feasible, considering both the maximum discharge temperature and the assumed chemical composition of the process effluent. However, the necessity for any effluent treatment should be evaluated during the design stage.

e. Fuel Storage Area Effluent

Leachate from the fuel storage area would be accommodated in perimeter ditches. The ditches may be directed to a sump for subsequent sludge disposal and effluent treatment.

f. Fire Protection and Potable Water Supply

Automatic sprinklers would be provided in the hog fuel conveyors, galleries and garage. The turbine generator oil system area would be provided with a carbon dioxide system or, if required by underwriters, a water sprinkling system.

The proposed fire protection system would be submitted to underwriters for approval during the detail design stage.

3. Structural Design

The following structures would be provided:

- Boiler house
- Turbine hall
- Administration building and garage
- Make-up water treatment facility
- Miscellaneous hog fuel handling structures and conveyor supports.

Detailed soils investigation at this conceptual design stage has been excluded. The cost estimates are based on reinforced concrete spread footings for all structures, and appropriate materials and technology for frames, roofs, exterior and interior walls, partitions, doors, etc.

4. Hog Fuel System

a. Supply and Transportation

Hog fuel for the generating plant is to come from six (or more) local sawmills in the Williams Lake area.

Transport is to be by "B"-train highway trucks except for possible direct conveying by belt or pneumatics from one or more mills directly adjacent to the proposed power plant site.

b. Receiving, Storing and Feeding

The on-site hog fuel system would be designed on the assumption that the fuel would be already hogged by the suppliers; however, provision must be made for screening of the receipts and for hogging that portion which is unacceptable as fuel. Provision would be made for a future rock separator. The system is illustrated on flow diagram 7801-461-04 and the physical arrangement is shown on drawing 7801-461-03.

Hog fuel being trucked to the site in "B"-train type trucks would be unloaded via a truck dumper into a hopper with an outfeed conveyor. The trucks would be weighed before and after unloading on a scale with electronic indication and ticket printer.

The dumping system would be capable of unloading six trucks per hour or 300 tons per hour (at 30 units per truck and a weighted average bulk density of 16.5 lb/cu.ft). The outfeed conveyor would feed on to a belt conveyor to a scalping disc screen. Hog fuel from the three mills adjacent to the site would arrive on a belt conveyor which would discharge to one common larger belt similar to the belt coming from the truck dumper hopper. This belt would also convey the hog fuel up to a dedicated scalping screen.

Above each belt's head drum would be a self-cleaning magnet to remove any tramp iron. The acceptable hog fuel would drop through each screen on to a common conveyor belt. The rejected material from each screen would pass through its own hammer hog and then drop on to the same take-away belt rated at 500 tons per hour. A bypass would provide for the transfer of overs from each screen on to the ground to allow maintenance of the hogs. The overs would be returned via front-end loader to one of the truck dumpers at a time when the hog was again operational.

The accepts would be conveyed and lifted on the single large belt to a transfer point where a second large belt would carry the screened and hogged fuel to the storage pile, discharging via a travelling tripper as far as the centre of the storage area. The tripper could also discharge near the reclaimer to allow a front-end loader to reshape the pile to give approximately 8 hours of live storage.

Two reclaimers, 60 m apart, would be provided to minimize the amount of bulldozing time, along a 120 m retaining wall. Up to two months of storage would be provided in a pile 240 m square and 10 m high to ensure continuous fuel supply regardless of seasonal variations or other interruptions.

The two reclaimers would have variable speed drives, would both discharge on to the same belt system and would normally operate one at a time which would allow for maintenance on the other. The belt would discharge to another scalping disc screen to remove any debris that may have entered the system. A final belt to the boiler house would be equipped with a self-cleaning magnet to remove any other tramp iron.

At the boiler house the belt conveyor would discharge to a distributing chain conveyor with outlets for the boiler feeders. Supply would be maintained at about 15 percent over boiler requirements by the remotely-controlled reclaimer conveyors. Excess hog fuel from the boiler distribution conveyor would be returned to the storage pile by a final belt conveyor. This belt would be capable of handling the full rate going to the boiler so an emergency shutdown at the boiler would not cause overloading and spillage.

All belt conveyors would be provided with walkways and with hoods over the belts. The maximum belt conveyor slope would be approximately 12 degrees to ensure no slipping of frozen material on the belts.

The preliminary layout and pile shape would be adjusted in detail design to best suit the final site shape and contours.

5. Water Supply and Distribution

a. Cooling Water Supply

Cooling water would be circulated at 2.5 m^3/s (36,400 GPM) by two pumps in a closed cycle through the turbine generator condenser and cooling tower. The tower is dealt with in more detail under the section headed "Power Plant".

b. Make-Up Water Supply

Make-up water is required for the cooling water loop and for the boiler steam/ condensate loop.

The cooling tower would require 43 L/s (682 GPM) of make-up to replenish losses due to evaporation and blowdown while the boiler feedwater system would require approximately 1.25 L/s (20 GPM). This would be provided from the town system.

6. Power Plant

a. General Arrangement

The location of the generating plant proper relative to the other station components is shown on 7801-461-03, while details of the plant layout have been shown on Drawings 7801-461-01 and 7801-461-02.

The plant would be located as close as practical to the hog fuel storage pile, leaving space for the mechanical fly-ash collectors and electrostatic precipitators, the stack, and the ash handling system. The location of the switchyard was selected for proximity to the Williams Lake substation.

The power plant itself would house the boiler with its ancillaries, the station electrical equipment (except transformers and 60 kV switchgear), the control room, laboratory and offices.

The auxiliary bay between the boiler house and the turbine hall would contain the deaerator and deaerated feedwater storage tank, boiler feed pumps, hog fuel conveyors and feeders, piping and main runs of power and control cabling.

A tunnel under the auxiliary bay may provide convenient access for service piping including the main cooling water pipes. Alternatively, capital cost savings may be effected during detailed design by encasing the pipes in concrete instead.

The garage, fuel storage and pumps, weigh bridge and water treatment plant would be strategically located as separate structures within the site boundaries.

General administration, stores, electrical and mechanical workshops, battery room, switchgear, and chemical environmental laboratory would be located

within the power plant building. The environmental laboratory would be equipped with all necessary monitoring facilities.

The stack and ash discharge bins would be outside the main plant building.

The station control room is located on the operating floor level between the boiler house and turbine hall.

The turbine hall is arranged to allow the use of the crane to serve the turbine generator, the boiler feedwater heaters, station heaters and kiln loop heaters. For protection of critical equipment, a dust- and vapour-tight wall would separate the boiler house from the turbine hall. The condenser is arranged for tube withdrawal into the auxiliary bay through a removable portion of the wall or a sliding door.

The annex of the turbine hall would house the switchgear, motor control centres, and battery room, and, on-grade, the air compressor.

b. Selection of Boiler and Turbine Operating Characteristics

The temperatures and pressures as shown on Table 8-1 were chosen as representative of economic current practice, particularly in consideration of boiler heat transfer, turbine heat rate and casing design. A formal evaluation will be required at a design development stage.

Table 8-1 - Heat Cycle Parameters

Item	Units	Quantity
Steam		
Steam at Superheater Outlet		
Pressure	MPag	11.0
Temperature	deg C	510
Flow	kg/s	60.7
Feedwater Temperature	deg C	180
Hog Fuel		
Fuel Flow Bone Dry	kg/h	38,000
Fuel Moisture Content	% WB	38.4
Turbine		
Rated Output	MW	60

c. Boiler

As mentioned above, the boiler would be rated at 60.7 kg/s (481,800 lb/h) of steam at 11.0 MPa (1595 psig) and 510°C (950°F) when burning hog fuel, natural gas, or any combination of the two.

The boiler and its associated equipment such as superheater, sootblowers, hog fuel distributors, firing and automatic ash removal system, economizer, steam

coil, tubular airheaters, forced-draft (FD), induced-draft (ID) and overfire air fans, flues, ducts, dampers, auxiliary natural gas burners, ignitors and supervisory safety system would be purchased complete and installed as one package from the vendor.
While there are many possible designs of boiler, this report and its cost estimate have been based on a conventional bi-drum unit with travelling grates for continuous ash removal. A single drum radiant unit and/or grates of the sloping bare-tube type with reciprocating foot and dump grates may be viable alternatives.

The boiler would be fitted with steam-operated sootblowers, automatically and sequentially controlled from a special section in the boiler panel in the central control room.

d. Turbine

For selected pressure/temperature conditions, three stages of feedwater heating are proposed. Although four or five stages might be considered for increased efficiency, the use of three stages is adopted for simplicity and reduced capital cost.

The turbine would be provided with steam extraction for station and kiln heating and feedwater heating loops only. This extraction would be uncontrolled, i.e. there would be no provision to control the pressure to these loops.

The generator is described in the section headed Electrical Power Supply.

e. Fly Ash Collectors

For cost estimate purposes, an electrostatic precipitator is included because it defines the upper limit of cost and because the particulate emission standard specified by the Ministry of the Environment can be ensured. The precipitator is used in conjunction with mechanical collectors at the airheater exit to reduce precipitator inlet loadings. The provision of bag filters versus precipitators is discussed under "Power Plant Environmental Considerations" and under "Thermal Plant Technology". The reinjection of char will effect the particulate size distribution and this distribution should be considered in the design stage. It is unlikely to affect significantly the cost estimate.

f. Stack, Breeching and Ducts

The stack would be approximately 3.5 m (12 ft) diameter and 58 m (210 ft) high, of mild steel construction, free standing, and complete with all statutory navigation markings and sampling gallery. Steel with low temperature toughness or special anti-corrosion properties could be further considered during the detailed engineering phase, but has not been included in the estimate.

All air ducts directly associated with the boiler would be included with the boiler. The flues between the boiler and the stack via the dust collection equipment and ID fans would be supplied by the boiler and/or dust collection equipment manufacturers. Isolating damper(s) would be fitted as necessary for maintenance purposes.

g. Boiler Feed Pumps

As required by the regulations, one motor-driven pump and one standby steam-turbine-driven pump would be provided, each rated at 100 percent of the total flow.

The pumps would be of standard design with hydraulic thrust balancing, standard radial and thrust bearings, leak-off systems, automatic recirculation and combined lubricating systems for pump and drive.

h. Deaerator

The deaerator would eliminate oxygen and carbon dioxide from the feedwater and would also act as a stage in the feedwater heating train. The deaerator would supply a feedwater storage tank of 10-15 minutes capacity at full boiler load.

i. Chemical Treatments

Boiler Feedwater

The boiler feedwater will be AVT (All volatile treatment) with the following features:

1. Oxygen scavenging and passification with synthetic hydrazine.

2. Iron dispersant treatment to prevent iron deposition on heat transfer surfaces.

3. pH control using volatile amines to elevate feedwater and condensate into the non-corrosive range.

A non-chromate system is proposed for corrosion protection and deposition control.

Allowance has been made in the capital cost estimate for all appropriate measuring tanks, metering pumps, pipework, valves, fittings and controls.

j. Desuperheating

Desuperheating sections would be incorporated into the stage heater design as applicable, and would be included in the feedwater heating train by the turbine supplier.

k. Ash Handling System

The ash handling system is basically a dry system. Ash would be collected from the travelling grate discharge, boiler siftings hopper(s), airheater hopper(s), mechanical collector hopper(s) and precipitator hoppers.

A travelling grate, if selected, would discharge into a water-filled grate-ash conveyor to cool the incandescent ash and to shatter any clinker formation. An inclined discharge section in the conveyor would minimize water carry-over. Ash from the mechanical collector and airheater hoppers will require classification and separation of residual char and inert ash. The char will be reinjected into the furnace by pneumatic transfer.

Ash from all sources would be discharged through rotary or flip-flop valves into dry branch conveyors and from these into the main conveyor. All conveyors would be the sealed drag link type.

The main conveyor would feed the ash silo, which could hold 24 h of ash production. For ultimate disposal, trucks would be loaded from the silo. A fast-acting discharge slide gate, devices for preventing bridging, a wetting screw for ash conditioning and dust control, and silo base cladding and heating coils for freeze protection would be provided.

l. Ash Disposal and Transport

Preliminary analysis of typical fly ash from a similar boiler to that proposed, indicates that ash may be disposed by landfill as a normal industrial waste (see Appendix 12).

m. Cooling Tower

The selected cooling tower system would incorporate induced draft, double cross-flow towers with two fill sections and a common air plenum chamber. The cold water basin would be of concrete, and the tower itself generally of non-toxic pressure-treated lumber and plywood.

The tower system would incorporate six cells and would be 78 m x 13 m in plan and 8 m high. Each of the six cells would have an induced draft fan driven through reduction gears by 100 kW motors.

n. Compressed Air System

A single compressed air system supplying instrument air for pneumatic control and service air for various operating and maintenance functions, was selected in preference to two separate systems. A single system of instrument air quality has the following advantages:

- protects control devices from accidental connection to service air

- reduces the number of compressors needed

- simplifies piping

- reduces maintenance.

One rotary compressor with one air dryer and two receivers of sufficient volume for safe, controlled plant shut-down would be provided.

A rotary compressor was chosen consistent with industrial practice, for its pressure stability, simplified foundation requirement, lower maintenance cost and favourable availability record.

o. Cranes

A 30 t bridge crane and a 5 t auxiliary hoist would be provided for installation and maintenance of the turbine generator.

The 30 t crane would be adequate for all lifts except the generator stator, which would be installed by jacking or other means.

p. Emergency Boiler

A standby heating boiler would be provided to heat the station in case of a winter outage. The boiler would be a complete packaged unit of the fire-tube, forced-draft type rated at 1.3 kg/s (10,000 lb/h) of dry and saturated steam at 1140 kPa (150 psig) feeding the station service heating loop.

The boiler would be suitable for either natural gas or No. 2 diesel oil fuels.

7. Station Heating

As the Williams Lake area is subject to severe winters, an efficient and trouble-free heating system would be provided to protect plant personnel and equipment. For estimating purposes a hot glycol system was included.

Central station heating would heat all buildings, the conveyor galleries, the hog fuel handling facilities, and the make-up-airheater. Provision has been made in the estimates for space heaters, glycol loop, intermediate hot water loop, and steam extraction loop.

The intermediate hot water loop between the extraction steam loop and the glycol station heating loop protects against leakage of glycol into the condensate, where it would destroy the condensate polishing resins. Leakage would be hard to detect and the consequences, if undetected, could be severe.

8. Administration and Maintenance Building

The Administration block would be a two-storey structure incorporated in the Power House Structure.

The upper level would contain the offices of the Station supervisory and clerical staff, lunchroom and washing facilities.

The ground floor level would contain the main workshop with access to the boiler house, a separate instrument and electrical workshop with offices for the supervisors of these functions, general storeman/watchman office and an environmental laboratory for the monitoring of water treatment and emissions. The laboratory would be provided with equipment suitable for routine tests on water and fuel quality, gas and stack analysis, etc.

Separate buildings will house make-up water treatment facilities, garage and loader refuelling stations.

9. Alternative Fuels and Operating Modes

a. Garbage Firing

A small proportion of garbage firing may be possible provided that metal and debris have been removed and that the feed meets the size specifications of the hog fuel. Receiving and handling facilities are not included in the cost estimate. 100% garbage incineration would require special design and additional costs and has not been considered herein.

b. Railroad Ties, etc.

The furnace may be capable of incinerating a small proportion of combustible hogged material such as railroad ties. This would require special testing and would take place only under permit from the Ministry of the Environment.

c. Kiln Heating

Heat could be provided to nearby sawmills by a hot water or thermal oil distribution system, heated by extraction steam. Supply and return piping, 75-150 mm (3-6 inch) diameter, would be encased in galvanized steel conduit, 460-650 mm (18-25 inch) diameter buried 2.5 m (8 ft), for frost protection. Individual pipes within the conduit would be fibreglass-insulated and the whole assembly would be factory-assembled in pieces complete with supports, anchors, expansion loops and end seals ready for installation into prepared trenches.

No allowance is made in the estimate for adaptation of the kilns or for metering the heat consumed.

d. District Heating

District heating was not considered in this study.

However, if a suitable site and heating load can be established, this matter could be given further consideration during the detail design stage or in a separate study.

e. Greenhouse Heating

The facility rejects large amounts of low temperature (approx. 30-40°C) heat to the atmosphere via the cooling tower. A proportion of this could be conveniently diverted for greenhouse heating, particularly for root zones or concrete floors. Costs for this are not included.

10. Station Control

The major components and auxiliaries of the plant would be supervised and controlled from the central control room.

A microprocessor-based programmable distributed control system (DCS) would be installed for all aspects of the facility's operation. Analogue controls will be installed as required by regulations. Multiple video screen process diagrams will be provided in DCS software for displaying on the DCS CRT monitor(s), for operator interfacing.

Local control can be provided for special procedures or equipment such as turbine start-up air compressor, precipitator, hog fuel truck dumper, etc. In addition, local start-stop functions near drives and close-trip functions on switchgear would be provided where required for maintenance and emergency operation. The options of controlling discrete devices (motor starters, solenoid valves, etc.) from a programmable logic controller (PLC) or from a multi-function controller embedded in the DCS, will be reviewed during the detail design phase.

11. Electrical Power Supply and Distribution

a. General

Electrical power would be generated at 13.8 kV, 60 Hz.

Approximately 90 percent of the power would be fed via a 70 MVA main transformer and 60 kV outdoor bus system into a 60 kV line feeding into BCHPA's Substation. The remaining 10 percent would be fed via a station service transformer into 4.16 kV and 0.6 kV distribution systems for the station auxiliaries.

b. Electrical Design Considerations

i. Continuity of Supply

No back-up or emergency equipment would be supplied other than what is required by personnel safety or operational flexibility.

ii. Voltage Selection

The generation voltage of 13.8 kV for this plant is consistent with modern practice for units of this size.

Motors above 300 kW would be connected to the 4.16 kV system. Motors 300 kW and smaller would be fed at 0.6 kV.

iii. Start-up Facilities

The electrical and mechanical systems have been designed to allow normal start-up only. A "black start" capability is not considered necessary.

During normal start-up, the plant would draw the power necessary to start the auxiliaries from the BCHPA network through the main transformer and station auxiliary transformer. All auxiliaries, including those of large kW requirements would be started across the line without the aid of start-up drives. When the generator has reached synchronous speed and voltage, it would be synchronized on to the system through its 13.8 kV circuit breaker.

iv. Synchronizing Facilities

In order to provide maximum operational flexibility for start-up conditions, synchronizing facilities would be provided across the 60 kV incoming circuit breaker (60 CB1), and the 13.8 kV generator circuit breaker (13 CB1).

v. Operation and Protection Facilities

Plant operational facilities such as controls, metering, and electrical circuit and equipment protection as well as personnel protection would be based on normally accepted practices of primary industries and utilities.

vi. Grounding Design

The 60 kV section will be ungrounded. Ground fault protection will be provided by voltage measurement with an open corner delta P.T. connection, and will be co-ordinated with BCHPA's ground fault protection.

The stations' 13.8 kV, 4.16 kV, and 0.6 kV systems would all be high-resistance-grounded to minimize ground fault currents and damage to equipment during faults. In the case of the 13.8 kV system, such grounding connections would be effected through the 13.8 kV winding of the main transformer as well as through the generator star point to ensure effective grounding before synchronization of the two entities.

A ground grid to limit step and touch potentials would be provided in the 60 kV switchyard, to which all electrical equipment and fencing would be connected in accordance with normal BCHPA practice.

Buildings would have a perimeter ground loop, to which major structural steel would be connected. All driven equipment would be grounded through ground wires in the motor feeder cables.

c. Plant Layout

i. High Voltage Switchyard

The 60 kV switchyard would be if the standard BCHPA low-profile type to minimize visual impact.

It would contain the 70 MVA main transformer, the 7.5 MVA station service transformer, and all 60 kV equipment switchgear, interconnected bus and support structures, surge and lighting protection, system and equipment grounding, lighting and fencing, all designed to BCHPA standards.

The substation would occupy an area approximately 40 m long and 20 m wide.

ii. Station Auxiliary System

The 13.8 kV connections to the generator switchgear and generator would be bus duct or alternatively multiple single core armoured (teck) cables on tray. Two station service transformers would be provided to feed the 4.16 kV and 0.6 kV systems respectively. All switchgear and motor starters would be located in a ventilated self-contained Electrical Room. The cables would be laid in cable trays. The auxiliaries in the hog fuel storage area would be supplied by a separate 750 kVA transformer fed by either an underground cable or a cable on tray in the conveyor gallery.

d. Equipment

i. Incoming 60 kV Transmission Equipment

BCHPA has provided the cost for the connection between the plant 60 kV switchyard and the Williams Lake substation including the necessary equipment and modifications.

ii. Generator

The generator would produce approximately 70.0 MVA at 0.9 power factor and 3600 rpm. It would be equipped with brushless excitation and automatic voltage regulation. The machine would be air cooled and would include surge protection close to the generator terminals. The generator temperature would be monitored by RTD's embedded in the stator winding, and RTD's in the bearings and cooling air circuits. It would be provided with detectors for shaft eccentricity and vibrations, differential expansion, shaft currents and other standard supervision features. Stator ground fault protection covering approximately 98% of the winding would be included in addition to normal overcurrent, negative sequence, reverse power and field failure protection.

iii. Transformers

All transformers would be oil filled and designed for outdoor service. They would be rated on the basis of natural cooling.

The main transformer would be provided with delta-connected primary and star-connected secondary windings to provide neutral grounding points for 13.8 kV system as mentioned above.

The main transformer would be provided with off-load taps on the windings to give some flexibility during long-term variations of 60 kV network voltages. It is not deemed necessary to provide on-load taps on this transformer as the excitation system of the generator should provide the necessary flexibility to take care of normal voltage fluctuations in the system.

For station service two separate two-winding transformers have been proposed, rated 13.8 kV wye primary and 4.16 kV delta and .6 kV delta secondary, respectively. The transformers would have off-load top changers. The stipulation by BCHPA that the voltage range of the generating station will be 0.95 per unit to 1.05 per unit makes the use of on-load top changers for the station service transformers unnecessary.

The transformers would be provided with standard overcurrent, ground current and gas pressure protection. In the case of the 60 kV transformer, differential protection would also be included.

During the detail design stage, provision of an overall differential protection scheme covering all transformers and their interconnecting buswork should be considered.

iv. Switchgear and Starters

For the purpose of capital cost estimates, an SF6 breaker was assumed for the 60 kV service, and vacuum break switchgear was assumed for the 13.8 kV and 4.16 kV systems.

Incoming supplies to the 4.16 kV and 0.6 kV distribution systems and subfeeders would be protected by fully-rated circuit breakers to avoid single phasing problems.

All 4.16 kV and 0.6 kV motor starters were assumed to be full-line voltage contactor types with fuses providing current limitation during short circuits.

v. Motors

Motors in general would be cage type induction machines, rated 575 V for sizes up to and including 300 kW, and 4 kV for sizes larger than 300 kW.

Motor enclosures would be as follows:

Rating	Enclosure	Application
0 - 90	TEFC	All
100 - 335	Dripproof TEFC	General case Outdoors and in areas with dust contamination
373 and larger	WP1 WP2	General case Outdoors and areas with moderate dust contamination
	Totally enclosed pipe-ventilated	Areas with severe dust contamination

vi. Variable-speed Drives

Variable-speed drives as required for hog fuel handling and ash handling would be voltage source variable frequency inverters, with standard 575 V cage induction motors.

The boiler ID fan drive would be either a DC motor with a 6-pulse thyristor bridge and unit transformer connecting the bridge to the 4160 V station service bus, or an AC load commutated inverter drive rated 4 kV, with synchronous motor with brushless exciter. The exciter would incorporate a 3 phase rotating stator field to provide main motor excitation at zero motor speed.

The use of variable-speed drives for the boiler forced draft fans would offer significant energy savings but would be substantially more expensive than the common arrangement with fixed speed fans and inlet dampers.

The use of variable-speed drives for the forced draft fans will be considered and evaluated during the detail design phase.

vii. Cables and Wiring

4.16 kV cable and 0.6 kV power and control cable would be teck type supported on ladder trays. Lighting circuits would be supplied by wiring in conduit.

Instrumentation wiring and compressed air tubing would be run on trays separate from power and control wiring.

viii. Battery

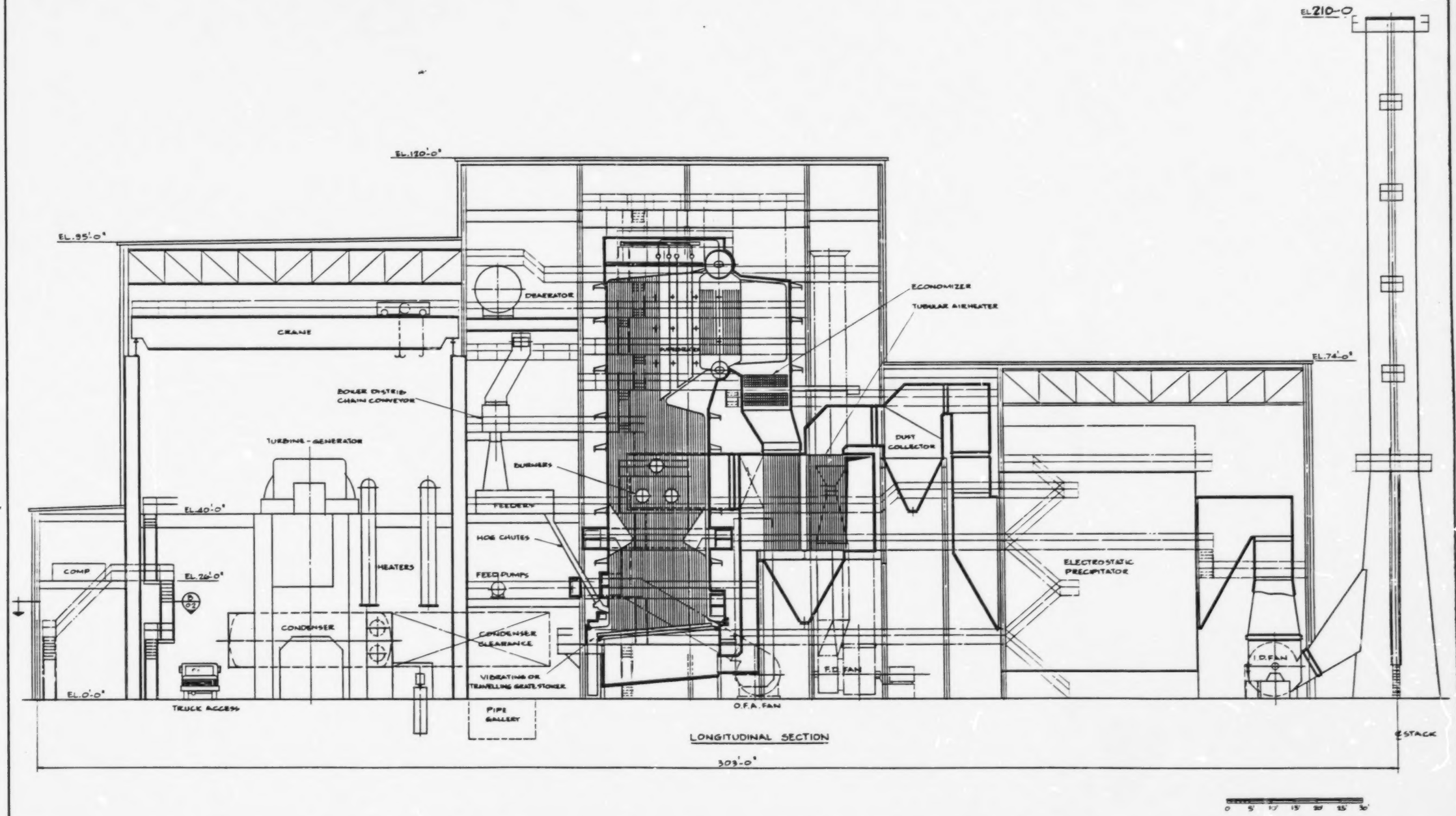
A 125 volt station battery of approximately 300 A-h and associated automatically controlled battery charger with rapid charge/float charge facilities would be provided to supply DC for the station controls.

The correct ampere-hour capacity of the battery would be established during the detail design phase when the total load and load cycle can be accurately determined.

ix. Lighting

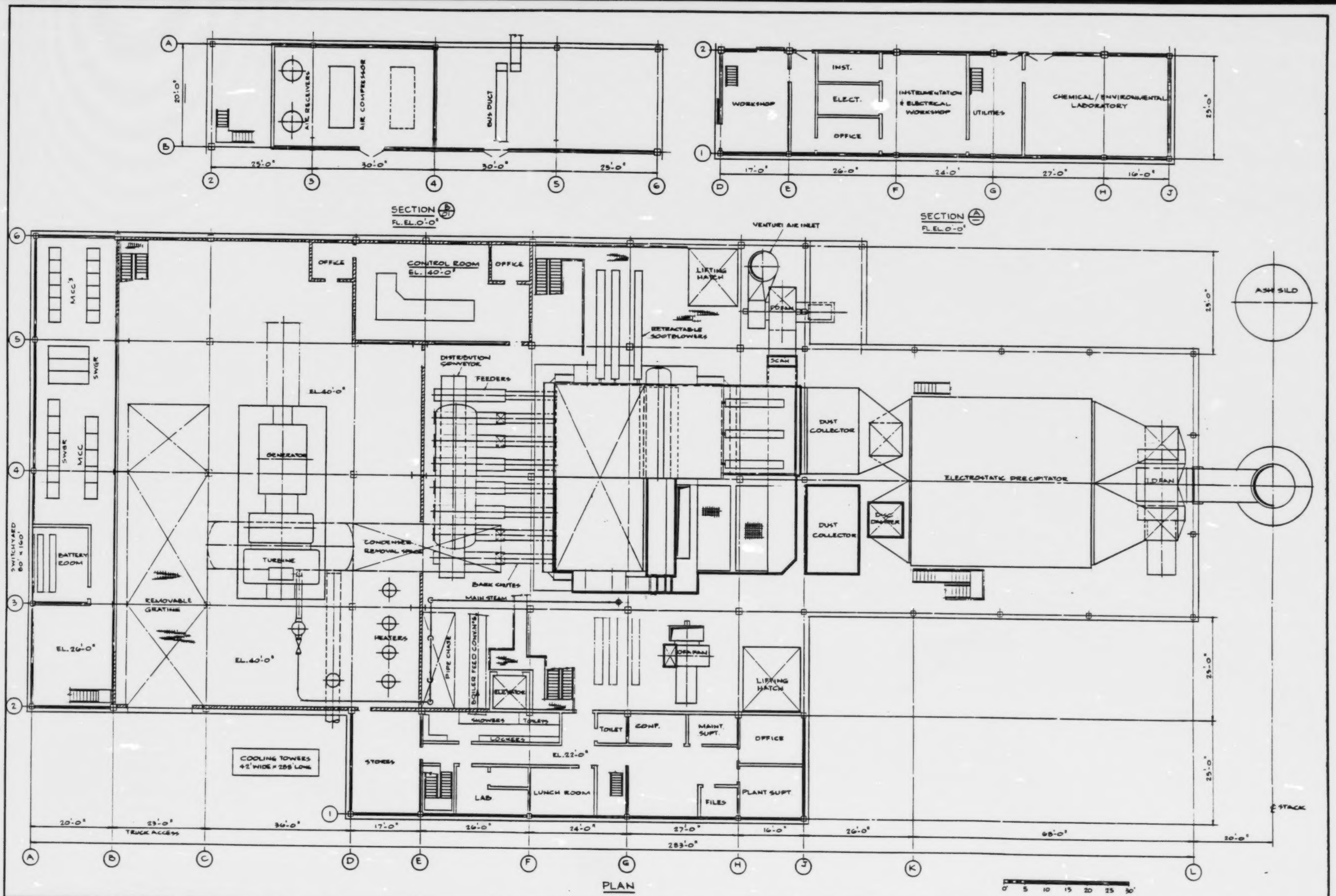
In general, high pressure sodium lamps would be used throughout the station because of their efficiency, long life and resulting low maintenance requirements. In offices and low-headroom areas, fluorescent lamps would be used.

Emergency lighting would be provided from self-powered battery packs or from central emergency supply units feeding emergency lighting in specific areas which may require lighting during a black start situation.



LONGITUDINAL SECTION

SANDWELL SWAN WOOSTER	60 MW POWER PLANT COMBIN. FUEL POWER BOILER LONGITUDINAL SECTION MINISTRY OF STATE CARIBOO REGION DWG. 7801-461-01 REV



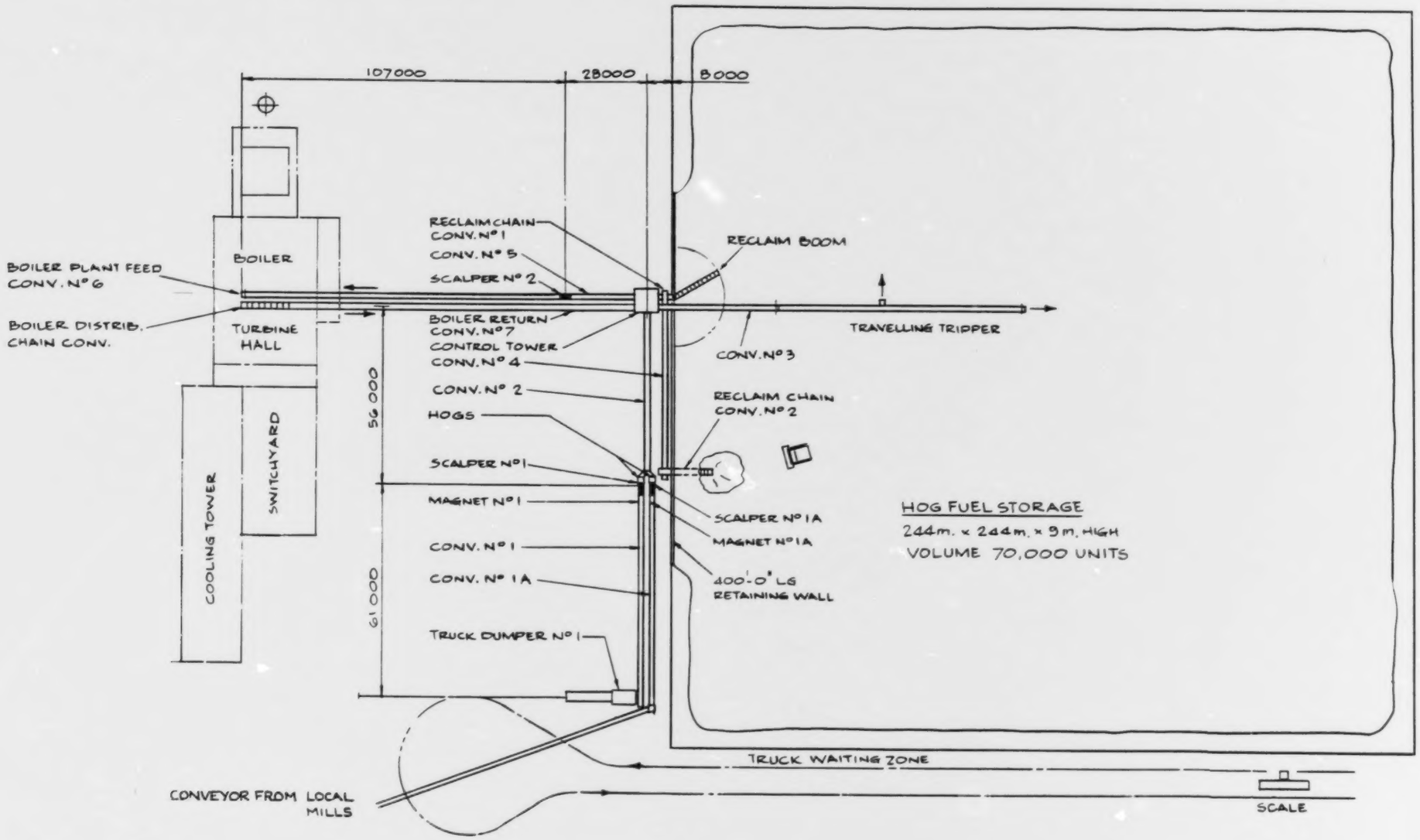
E.

SANDWELL SWAN WOOSTER

60 MW POWER PLANT
COMBIN. FUELS POWER BOILER
PLANS & SECTIONS

MINISTRY OF STATE
CARIBOO REGION

DWG. 7801-461-02 REV



APPROVED	SCALE		
DATE	DRAWN	KTH	8-91 6
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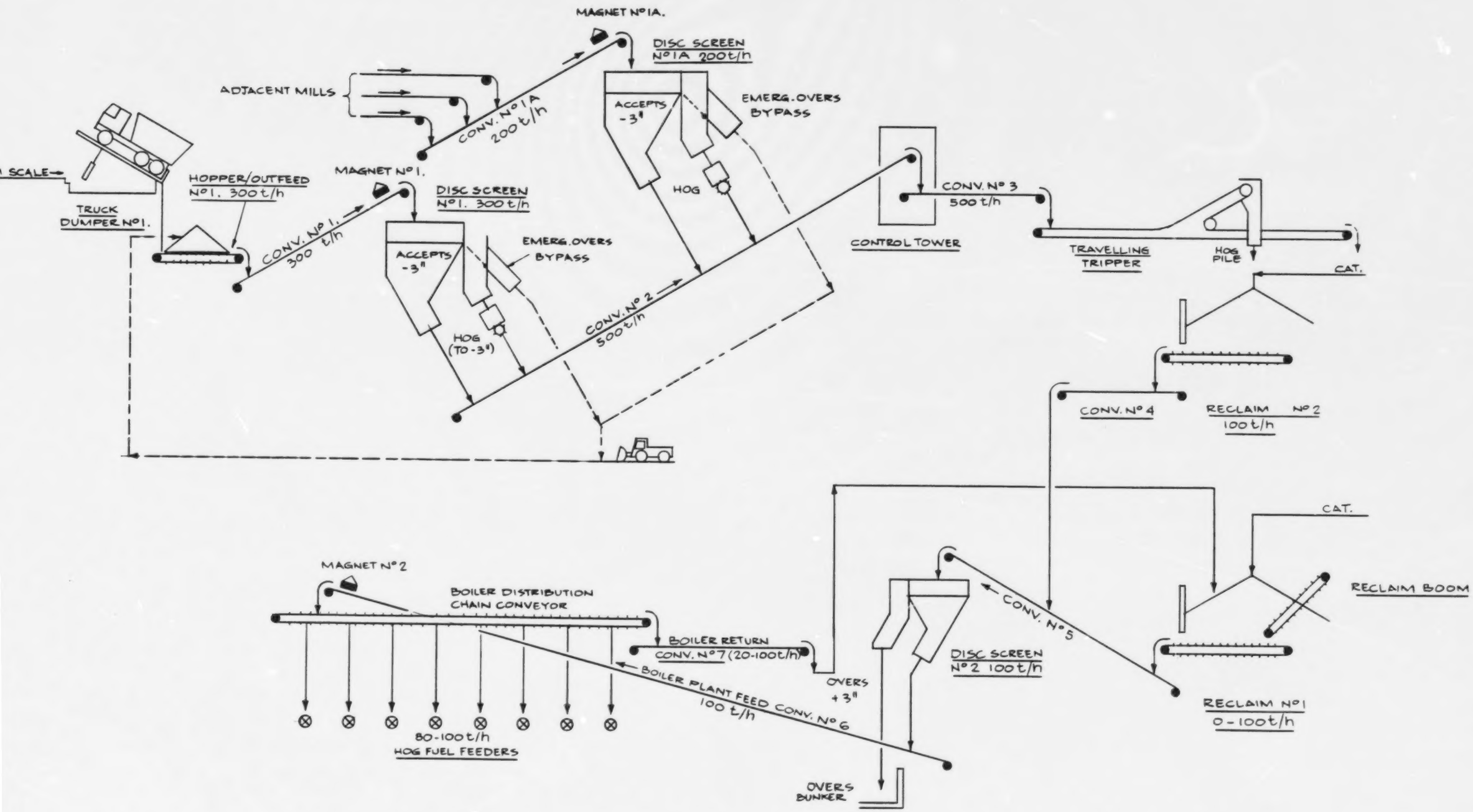
SANDWELL SWAN WOOSTER

THERMAL GENERATING PLANT
PRELIMINARY LAYOUT

MINISTRY OF STATE
CARIBOO REGION

DWG. 7801-461 - 03 REV



SCALE	NTS		STEAM GENERATING PLANT
DRAWN	KTH	89 1 6	FUEL HANDLING SCHEMATIC
D			
SANDWELL SWAN WOOSTER			MINISTRY OF STATE CARIBOO REGION
			DWG. 7801-461-04 REV

APPENDIX 9

B.C. HYDRO & MARKETS

REPORT X7801/1
CARIBOO WOODWASTE STUDY

MINISTER OF STATE
CARIBOO DEVELOPMENT REGION
VICTORIA BRITISH COLUMBIA

DATE 9 MARCH 1989

APPENDIX 9 - B.C. HYDRO'S 20 YEAR PLAN AND OTHER POWER MARKETS

1. B.C. HYDRO'S 20 YEAR PLAN

In March 1988, B.C. Hydro issued their 20-year resource plan for the period 1988 to 2007. B.C. Hydro's "20 Year Resource Plan 1988 - 2007" Vancouver, B.C. B.C. Hydro issues their long-range resource plan each year. The plan describes B.C. Hydro's strategy for meeting future customer requirements for electricity in B.C. Hydro's service area. The highlights of the 1988 plan are described below.

B.C. Hydro expects to have a firm hydro surplus until 1989. When this firm hydro surplus is combined with thermal generation plus off-peak purchases from Alberta, B.C. Hydro's loads will be satisfied until 1995. In the near term, B.C. Hydro intends to market its firm surplus of power to both domestic and export markets. In the long term, B.C. Hydro intends to rely on power purchases and utility coordination agreements to postpone the need for new generation until after the turn of the century. B.C. Hydro also intends to pursue cost-effective demand side management and other energy saving measures to delay the need for new generation.

By the year 2003, demand side management programs are projected to avoid approximately 350 avg. MW of new generation. Additional coordination with the Bonneville Power Administration is expected to increase the energy output of the hydro system by approximately 150 avg. MW beginning in 1989. The purchase of approximately 350 avg. MW from Alcan is projected to begin in 1995. Beginning in 1998, B.C. Hydro will be entitled to the return of the Columbia River downstream benefits as specified in the 1961 treaty between the United States and Canada. The amount of power from downstream parties is expected to be approximately 550 avg. MW. Three hydro projects are planned just after the turn of the century. They include Peace Site C, Keenleyside and Murphy Creek and will add approximately 840 avg. MW of generation. Finally, the Hat Creek Coal Project, planned for the year 2006, has an annual energy capability of approximately 1350 avg. MW.

The capability and cost of B.C. Hydro's resource alternatives as described in the 20-year resource plan is shown in Table A.

TABLE A

Project	Capacity MW	Critical Capability GWH	Average Capability GWH	Total Capital Cost In Millions of Dollars	Uniform Energy Costs ¢/kWh
Peace Site C	900	4,570	4,710	1, 637	3.0
Keenleyside	240	1,040	1,160	347	2.5
Murphy Creek	275	1,380	1,450	677	3.6
Seven Mile	203	140	290	70	1.5
Stikine-Iskut	2,900	13,130	15,570	6,343	4.0
Liard	3,190	16,730	18,380	6,664	4.3
Homathko (3 projects)	895	4,440	4,360	2,349	4.7
Hat Creek (Coal)	2,000	13,140	11,800	2,915	3.2

Source: Appendix III of B.C. Hydro's 20-year Resource Plan dated March 1988.

Note: Capital Costs and Energy Costs are in October 1987 dollars.

In 1988-89, a provincial export policy will be developed. This policy could move up the completion dates for some of the resources described above assuming the intent is to build these projects prior to need and sell the surplus generation on the export market. This export policy is described later under the U.S. utility markets section.

B.C. Hydro's resource plan assumes a 20-year energy load growth rate of 2.8% per year. The probable high load growth rate is 3.3% per year and the probable low load growth rate is 2.2% per year.

B. C. Hydro also intends to pursue new interconnections with Puget Sound Power and Light Company and the Washington Water Power Company. These interconnections would increase sales to firm and secondary energy and capacity. The interconnections are expected to add 1,000 MW of capacity and 750 avg. MW of energy load to B.C. Hydro's system. The interconnection with Puget Power is expected to be completed in 1992, and the interconnection with Washington Water Power is expected to be completed in 1995. The commercial arrangements associated with these interconnections may require new generation described above to be advanced by two or three years.

Columbia River downstream benefits will revert back to British Columbia beginning in 1998. If the Province decides to sell this benefit to the U.S. utilities, additional

resources will be needed on B.C. Hydro's system to cover this sale.

B.C. Hydro is studying the potential benefits of additional coordination with TransAlta utilities. B.C. Hydro would purchase TransAlta's off-peak coal-fired energy and thereby make B.C. Hydro's hydro resources more usable. A study on the benefits of this coordination was initiated in 1988.

The resource plan announces B.C. Hydro's intention to purchase power from private producers and cogenerators. B.C. Hydro issued a policy in December 1988 regarding the purchase of electricity and load displacement in integrated and non-integrated areas. This policy is described below.

2. INDUSTRIAL USERS IN THE CARIBOO

Cost of Power for Industrial Users in the Cariboo

B.C. Hydro has an electric tariff on file for large industrial users (5,000 kW and over). The tariff is effective March 25, 1988 and is designated Schedule 1821. Service under this schedule is at 60 kV or higher. The following charges are in Canadian dollars. The demand charge is $3.918/kVa of billing demand per month. The energy charge is 2.239¢/kWh. The billing demand is equal to the greater of 1) the maximum demand for that month; 2) 75% of the highest maximum demand in any of the immediately preceding 11 months or; 3) 5,000 kVa. The minimum monthly charge is $3.918 per kVa of billing demand.

Wheeling Power to Industrial Users

In the policy on purchase of electricity and load displacement for the integrated system from projects greater than 5 MW, dated December 1988, B.C. Hydro states it will consider wheeling of electricity from an IPP to the IPP's customer, where it is for the incremental load within the B.C. Hydro service area, and where sufficient capacity exists, and is likely to continue to exist, in the B.C. Hydro transmission system. Based on these restrictions, power from the Williams Lake Project could only be wheeled to incremental new loads within the B.C. Hydro service area.

The rates for wheeling services are currently under development by B.C. Hydro and would have to be negotiated. In addition, any B.C. Hydro system reinforcements prior to providing wheeling services from Williams Lake would have to be paid by the project. The project may also have to pay for B.C. Hydro studies required to determine the feasibility of the wheeling proposal.

Comparison of Williams Lake Project Costs With Industrial Users Alternative Power Costs

B.C. Hydro is willing to wheel to new industrial loads. The rate to such industrial loads would have to be competitive with B.C. Hydro's industrial tariff. Assuming a 75% capacity factor, the current industrial rate is 3¢/kWh (Canadian Dollars). This is less than B.C. Hydro's current long-term marginal cost (3.4¢/kWh).

Sale of Williams Lake power to an industrial customer would incur the added cost of wheeling. With this added cost and since the industrial rate is less than B.C. Hydro's current long-term marginal cost, it appears that selling power directly to

B.C. Hydro would provide more revenue to the project than selling to an industrial customer assuming B.C. Hydro is willing to negotiate rates equal to their marginal cost. However, under the RFP process, the Williams Lake Project will have to compete with other resource proposals and the rates submitted with such proposals may be well below B.C. Hydro's long-term marginal cost.

3. U.S. UTILITY MARKETS

Export Agency

A new agency has recently been formed in British Columbia to oversee the export of power from British Columbia to the United States. The agency might encourage the development of power projects in British Columbia prior to their need in British Columbia. To be considered for export, the capacity of a proposed project must be at least 50 MW. Assuming a market can be found in the U.S. for such power projects, they would be developed and sold to U.S. markets for a period of years and then used for British Columbia's needs upon expiration of the sale. The cost of developing these projects will have to be recovered from revenues received from the export sale.

B.C. Hydro Wheeling Policy

Based on the policy on purchase of electricity and load displacement in integrated and non-integrated areas, B.C. Hydro will only provide wheeling of power from an IPP to incremental loads within B.C. Hydro's service area. If an IPP wished to sell power to a United States entity, the transaction could only be handled by the Export Agency. If the Export Agency approved the transaction, the Agency would purchase power from the parallel generator along with wheeling and other services from B.C. Hydro and then sell the power package to the U.S. entity.

Markets in the Northwest

The Pacific Northwest region is currently experiencing a firm surplus of power.[1] The only utility in the region in need of additional resources is Puget Sound Power and Light Company located in the Seattle area.[1] Puget Power has recently signed numerous firm purchase power arrangements with other Northwest utilities to satisfy their needs. it is expected that Puget Power will continue to need additional resources into the 1990's and beyond. The remaining utilities in the Pacific Northwest region will need additional resources in the mid to late 1990's and beyond the year 2000 assuming loads continue to grow at the current annual rate of 1-2%.[1]

Bonneville Power Administration is also currently surplus and is expected to need resources in the 2003-04 period. Bonneville is currently marketing their capacity and energy surplus to utilities in both the Northwest and Southwest. Over the next three to four years, most of the exiting surpluses in the Pacific Northwest will diminish. At that time, only the most economical new resource proposals will be pursued. These proposals will have to compete with the utility's other resource

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1 Northwest Regional Forecast, Pacific Northwest Conference Committee, March 1988.

alternatives including conservation, power purchases, cogeneration, etc.

Markets in California

Like the Northwest region, the utilities in California, as a group, are also currently experiencing a power surplus.[2] However, a number of firm power sales from Northwest utilities to California have been completed within the last three years. Northwest utilities have been selling their firm surplus to California utilities on a long-term basis; most of these sales have been in excess of 15 years in term. The rates for these firm sales have been discounted in the early years to reflect the existence of firm surplus. Therefore, the rate for power over the entire contract term is less than that required to support the construction of new resources. Contracts with a term in the range of 5-15 years will currently bear a price of 2-4¢/kWh (U.S. dollars). Contracts with a term in the range of 15-30 years will currently bear a price of 4-6¢/k (U.S. dollars).

Most California utilities are expected to need new resources in the mid to late 1990's.[2] California utilities are expected to use a bidding process when they begin requesting proposals for the development of new generation resources. Projects requiring a short lead time for construction will have an advantage. Utilities will be less willing to commit to resources requiring commitments more than five years prior to their need.

Once the need is identified, and utilities begin requesting proposals for new generating resources, only the most economical resources will be selected for development. It is expected that utilities in California will be willing to pay as much as $60/MWh (lifetime levelized cost, U.S. dollars) for new generating resources that would come on-line in the mid to late 1990's.

For the Williams Lake Project to compete in either the Pacific Northwest or the California market, transmission costs must be added to the project costs when making comparisons. The ability to wheel Williams Lake Project power to either the Pacific Northwest or California will require the services of B.C. Hydro and the Bonneville Power Administration or additional transmission.

As stated earlier, B.C. Hydro's transmission costs are not yet available. BPA transmission costs for wheeling services to a Pacific Northwest market would include charges associated with the Northern Intertie and the Main Grid. BPA transmission costs to markets in California would involve charges associated with the Northern Intertie, the Main Grid, and the Southern Intertie. BPA's Northern Intertie and Main Grid transmission charges should remain relatively stable assuming BPA does not add any major transmission projects to those two systems. The Southern Intertie transmission charges are expected to approximately double in the early 1990's upon completion of the DC upgrade and the Third AC. In addition, the sale of the Williams Lake Project to either a northwest or a southwest utility would be subject to the conditions of BPA's Long Term Intertie Access Policy. The current Long Term Intertie Access Policy places Canadian exports to U.S. markets at the bottom of the list of priorities for intertie use.

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2 Summary of estimated loads and resources, Western Systems Coordinating Council, Jan. 1, 1988.

The current nonfirm wheeling rates for the Northern Intertie, Main Grid and Southern Intertie are 1.05 mills/kWh, 1.4 mills/kWh and 1.61 mills/kWh (U.S. dollars), respectively. Although these are nonfirm wheeling rates, they should be a close approximation of the firm wheeling rates that would actually apply. Associated losses are 1.9%, 1.6% and 3%, respectively. These rates and losses are additive for the sections of transmission used.

There are currently two non-federal interconnections being planned between B.C. Hydro and U.S. utilities. One is an interconnection with Pugent Sound Power and Light Company and the other is with the Washington Water Power Company. Both lines are currently in the planning stages. The Washington Water Power Company has applied for a presidential permit for their line. Both lines are expected to be completed by the mid 1990's. The restrictions associated with transmission provided by the Bonneville Power Administration could be avoided by pursuing a transmission path with either Washington Water Power or Pugent Sound Power and Light.

Markets in Utah and the Desert Southwest

The Desert Southwest area is also currently experiencing a firm surplus that is expected to last into the mid to late 1990's. The only power system experiencing substantial growth and the need for new resources is Nevada Power Company. The problem with serving the Desert Southwest market is transmission access. The only current direct path to the Desert Southwest market is through Utah Power and Light Company. In the past, Utah Power and Light has been unwilling to enter into wheeling or transmission agreements to allow commercial arrangements between utilities in the Pacific Northwest and the Desert Southwest.

Pacific Power and Light Company and Utah Power and Light Company are currently proposing to merge. FERC has approved the merger of these two companies subject to performance of specific wheeling conditions listed in the FERC order. If the merger goes forward and the wheeling conditions are accepted by Pacificorp, transmission access will be available to the Desert Southwest utilities. However, transmission access to the Desert Southwest utilities for the projects coming on-line in the early to mid 1990's (i.e.: the Williams Lake Project) will be at cost equal to the marginal costs of transmission facilities required to be built to deliver the power. The costs of new transmission projects are relatively high and such costs would have to be added to the Williams Lake Project costs and then compared with other generation alternatives available to Desert Southwest utilities in the 1990's. The cost of transmission between the Williams Lake Project and Utah Power and Light's system should also be included. This would include transmission costs through B.C. Hydro's system and either BPA, Puget Sound Power and Light, or Washington Water Power.

Projected Sale Rates to U.S. Utilities

The following are prices of recent sales made in the U.S. These give some indication of the price that could be obtained for Williams Lake power. Transmission costs, in addition to the cost of Williams Lake, must be recovered by the sales price.

U.S. MARKETS
ALTERNATE POWER COSTS
(U.S. DOLLARS)

	Levelized Rate ($/MWh)
Existing Power Purchase Contracts	
BPA Sale to Puget Power	30 (1989-2001)
BPA Sale to SCE	49 (1992-2011)
BPA Proposed Sale to MSR	57 (1992-2011)
PP&L Sale to SCE	52 (1992-2011)
BPA NR Rate	51 (1992-2011)
Puget Power Avoided Cost	61 (1992-2011)
City of Spokane Sale to Puget	58 (1992-2011)

	Total Construction Cost ($/kW)	Levelized Fuel and O&M Cost ($/MWh)	Total Levelized Cost ($/MWh)
Combined Cycle CT[2]	636	41	60
Coal Plant[2]	1825	29	85

1. Assumes 75% capacity factor and a 9.4% discount rate. Levelized rates are estimates based on certain assumptions used to calculate the rates.

2. Northwest Power Planning Council Draft 1988 Supplement to the 1986 Northwest Power Plan, November 1988. Figures assume a plant factor of 75% and a Fixed Charge Rage of 20%. A combined cycle CT or a coal plant would not be built until the late 1990's or possibly beyond the year 2000. Construction costs exclude interest and escalation incurred during construction.

APPENDIX 10

TRANSPORTATION COST DATA

REPORT X7801/1
CARIBOO WOODWASTE STUDY

MINISTER OF STATE
CARIBOO DEVELOPMENT REGION
VICTORIA BRITISH COLUMBIA

DATE 9 MARCH 1989

APPENDIX 10 - TRANSPORTATION COST DATA

BACKGROUND

Woodwaste as a thermal fuel is for a relatively low heating value 22.1 MJ/kg compared to coal on the order of 50 to 60 MJ/kg. Consequently thermal plants should be located so as to minimize the transportation cost of the fuel which in most cases is free.

Conveyors, truck/trailer units and rail cars are all options available for woodwaste transport in the Cariboo Development Region. As the region is relatively well served with major highways and railways, both modes can offer about the most competitive prices possible.

The major centres of woodwaste are shown in Table 10-1 below. Although mills may be scattered within a community the volumes represent the consolidated amount within a reasonably short haul distance.

Table 10-1 - Woodwaste Volumes in Regional Centres

	Annual Volume BDUs (000)
Major Centres of Woodwaste	
Williams Lake	293.8
Prince George	374.4
Quesnel	202.0
Minor Centres of Woodwaste	
100 Mile House	173.0
Bear Lake	85.6
MacKenzie	53.0
Mcbride	36.0
Valemount	24.0

Figure 1 (in body of report) shows the potential centres which, if woodwaste was used as fuel for facilities in each centre, would be potential woodwaste collection and possible cogeneration sites. Quesnel has a relatively large volume of available woodwaste. However, its location, between larger woodwaste centres of Prince George and and Williams Lake, would make overall regional collection costs higher than if plants were located as shown on Figure 1. For example, backhaul by chip trucks from Williams Lake would reduce unit haulage costs by about 40 percent.

Rail service north south with B.C. Rail and east west with C.N. Rail is reliable and efficient. Interlining (switching a load from one railway company to another) tends to be more costly and operationally less flexible so that hauling arrangements should avoid the situation if possible. The cost of loading and unloading facilities for railcar shipment are significantly higher than for trucks. This means that in general, rail transport is attractive for longer hauls (in excess of about 100 kms) and where annual volumes are sufficient and reliable enough to amortize the capital costs.

TRUCK/TRAILER COSTS

Conventional semi-trailer and tandem ("B" Train) chip transporters are suitable for woodwaste.

Vehicle	Capacity (Tonnes)	(BDU's)	(Volumetric) Units	Hourly Charge* (1 Hr.)
"B" Train	36	20 - 23	28 - 30	70 - 75
Semi Trailer	22	12 - 14	14 - 16	55 - 60
Tandem Truck	15	9 - 10	11 - 12	45 - 50

* Rate quoted includes return time (Arrow Transport and Domans Marpole Transport)

Loading and unloading times for the "B" Train units are bout 20 - 30 minutes with time allowed for vehicle positioning, tarpalin handling and vehicle check. Average highway speeds are about 65 kmph.

The upper range of unit costs for woodwaste hauled by "B" Train trucks is:

$$\text{Round Trip km's} \frac{\times\ 7500¢}{65\ \text{kph} \times 36\ \text{T}} + \frac{7500}{36} = \text{Cost ¢/T/km}$$

$$\text{kms} \times 3.2¢ + 208 = \text{Cost ¢/T/km}$$

Therefore, hauling costs from Quesnel to Williams Lake (240 km's return) would be about $9.50/T. Woodwaste moved as a backhaul from Quesnel pulp mill would be about $7.00/T. From 100 Mile House the cost would be $8.50/T. With competitive pricing and secure longer term contracts, the above unit prices might be lowered.

RAIL COSTS

Quoted rail rates for woodwaste have been obtained to provide cost comparison and general strategic assessment of options. Rates obtained are shown in Table 10-2 as follows:

Table 10-2 - Comparative Rail Costs - Woodwaste Transport

	Rate	
	$/VMU	$/T
McBride - Prince George - Williams Lake (380 kms)	42.10	27
Prince George - Williams Lake (240 kms)	22.30	15
100 Mile House (Exeter Station) - Williams Lake (100 km)	15.30	10
Quesnel - Williams Lake (120 km)	18.50	12

CONVEYOR COSTS

For distances typically less than 1 to 2 kms, conveyors offer a competitive alternative to trucks.

Costs for conveyors vary considerably. In the case of systems suitable for unseparated woodwaste moved from mills adjacent to the proposed thermal plant, costs have been estimated as follows. As the three mills have different volumes of woodwaste, the cost of conveyor transport has been based upon combined conveyor costs over the forecast annual woodwaste generated.

Estimated operating cost/BDU	=	$1.00/BDU
Capital cost (over 30 years)	=	$1.25/BDU
	Total	$2.25/BDU

The rate for conveyor woodwaste transport from the adjacent mills is equivalent to about $1.30/T.

APPENDIX 11

ENVIRONMENTAL GUIDELINES

Province of
British Columbia

Ministry of
Environment

Waste Management Branch
Blanshard Street
Victoria
British Columbia
V8V 1X5

3.3080.2
3.4032

COPY

October 18, 1988

Mr. K.J. Charpentier, P. Eng.
Business Development Services
Sandwell Swan Wooster
700 - 1190 Hornby Street
Vancouver, B.C.
V6Z 2H6

Dear Mr. Charpentier:

Re: Woodwaste Feasibility Study
- Electric Power Generation

Mr. Chris Stanley-Jones, Regional Development Officer, Ministry of State for Cariboo has requested me to respond to your enquiry of October 13, 1988 regarding the environmental restrictions for woodwaste fired cogeneration units. Presently, the Pollution Control Objectives for woodwaste-to-energy type facilities are being investigated, and no single document can be provided for your perusal. However, for your study the following general guidelines are provided, and the details of any particular aspect will be clarified at our meeting on October 19, 1988.

1. The following published documents shall be consulted in order to address various potential environmental concerns associated with steam electric power generation industry:

   - Environmental Codes of Practice for Steam Electric Power Generation. Design Phase, Report EPS 1/PG/1, March 1985, Environment Canada.

   - Environmental Codes of Practice for Steam Electric Power Generation. Design Phase, Appendices, Report EPS 1/PG/1A, December 1986, Environment Canada.

   - Environmental Codes of Practice for Steam Electric Power Generation. Siting Phase, Report EPS 1/PG/2, March 1987, Environment Canada.

Although these documents are addressed to fossil fuelled and nuclear power stations, several guidelines recommended therein are considered to be applicable to woodwaste fired power stations. Copies of these reports are available from Environment Canada.

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2. With respect to control of emissions from the power boiler, the following major guidelines shall be considered:

   - The best available control technology for particulates emission, namely a combination of multiclone and fabric filters, shall be considered. The total particulates emission shall not exceed 0.01 mg/KJ of heat input. This particular control technology is able to capture fine particles as well as limit emissions of toxic organic compounds which are increasingly becoming matters of concern.

   - The opacity of the stack emission shall not exceed 10% at any time during normal operations.

   - The emission of sulphur dioxide shall not exceed 0.004 mg/KJ of heat input.

   - The emission of nitrogen oxides shall be controlled by proper design of the furnace and operating procedures, it shall not exceed 0.1 mg/KJ of heat input.

   - Continuous monitoring of opacity of the stack gas, and of concentrations of carbon monoxide, carbon dioxide and oxygen therein shall be required.

3. The ambient air quality levels to be achieved for various contaminants will be supplied to you within two weeks.

4. The pollution control objectives for boiler blowdown wastewater discharges from the plant shall be equivalent to or better than:

pH	6.5 to 9.5
PCB's	Separate containment
TRC	0.2 mg/L
Fe	1.0 mg/L
Cr, Cu, Ni, Zn	0.5 mg/L
Cr (hexa)	0.05 mg/L
TSS	15 mg/L
Oil & Grease	15 mg/L

(The above are subject to revision subject to site specific receiving environment criteria

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5. Yard runoff water shall be directed to a designed collection point and will be evaluated in the future by a sampling and analysis program. Treatment of such effluent may be required dependent on the analytical results.

6. Prior to prescribing the requirements for ash disposal by landfilling, it is requested that the characteristics of both bottom and fly ash should be determined and provided to us. In this regard the analysis of the ash samples can be arranged by the Ministry. It is requested that you make arrangement for collecting separate samples of bottom ash and fly ash from the plant of Washington Water power at Kettle Falls and sending them to Dr. R.B. Swingle, Director of the Environmental Laboratory in Vancouver. You may wish to contact Dr. Swingle by telephoning 660-1689 and arrange for the supply of the ash samples.

If you have any further questions on this subject, please do not hesitate to call me at 387-9983.

Yours very truly,

K.K. Bhattacharyya

K.K. Bhattacharyya, Ph.D., P.Eng.
Technical Services

cc: Dr. R.B. Swingle
Mr. C. Stanley-Jones
Mr. H.J. Vogt

APPENDIX 12

TYPICAL ASH ANALYSIS

ENVIRONMENTAL LABORATORY
Report for form 00424925

Air Emiss. Mgmt. - Air Program ATTN: WILSON R Sample 88013136

Site: NOSITE CARIBOO WOODWASTE PROJECT FLYASH

From : 88/11/23:0000 To : 88/11/23:0000
Depth Range : 0.0 0.0 Tide :
Sample State: Others
Sample Comment:

Parameter Description	Result	Units	Analytical Technique (Sparcode/Medium/Pres'n)
Residue Tot. Volatile	30.4	%(W/W)	D/Q: /Grav. 550C (00320750/00/00)
Carbon Tot Inorganic	26400	ug/g	Ash on Leco (01240941/00/00)
Carbon Total	176000	ug/g	D/Q: Leco Carbon (C--T0790/00/00)
Metals Special Analy			Special Analysis (MTSPMTSP/00/00)
SWEP Metals (in duplicate)	mg/l		mg/l
Arsenic	<0.001		<0.001
Barium	0.51		0.53
Boron	3.53		3.50
Cadmium	<0.01		<0.01
Chromium	0.18		0.20
Lead	<0.1		<0.1
Selenium	<0.001		<0.001
Silver	<0.0005		<0.0005
Zinc	0.033		0.033
Mercury	<0.05	ug/l	<0.05 ug/l
Fluoride	<0.1	mg/l	<0.1 mg/l
FLYASH (in duplicate)	ug/g		ug/g
Total Arsenic	5		3
Total Antimony	4		5
Total Cadmium	4.3		4.5
Total Chromium	87.9		86.3
Total Lead	150		155
Total Mercury	<0.05		<0.05
Total Zinc	359		372

The cost of this special analysis was $ 653.76

ENVIRONMENTAL LABORATOR\

Report for form 00424925

Air Emiss. Mgmt. - Air Program ATTN: WILSON R Sample 88013136

Site: NOSITE CARIBOO WOODWASTE PROJECT FLYASH

From : 88/11/23:0000 To : 88/11/23:0000

Depth Range : 0.0 0.0 Tid

Sample State: Others

Sample Comment:

Parameter Description	Result	Units	Analytical Technique (Sparcode/Medium/Pres'n)	
Organics Special			Org. Special Analysis (ORSPORSP/00/00)	
Polynuclear Aromatic Hydrocarbon:	Replicate #1		Replicate #2	
NAPHTHALENE:	0.19	ug/g	0.15	ug/g
ACENAPHTHYLENE:	< 0.0025	ug/g	< 0.0025	ug/g
ACENAPHTHENE:	< 0.002	ug/g	< 0.002	ug/g
FLUORENE:	< 0.005	ug/g	< 0.005	ug/g
PHENANTHRENE:	< 0.0003	ug/g	< 0.0003	ug/g
ANTHRACENE:	< 0.0003	ug/g	< 0.0003	ug/g
FLUORANTHENE:	< 0.0005	ug/g	< 0.0005	ug/g
PYRENE:	< 0.002	ug/g	< 0.002	ug/g
BENZ(a)ANTHRACENE:	< 0.0006	ug/g	< 0.0006	ug/g
CHRYSENE:	< 0.0005	ug/g	< 0.0005	ug/g
BENZO(b)FLUORANTHENE:	< 0.001	ug/g	< 0.001	ug/g
BENZO(k)FLUORANTHENE:	< 0.0003	ug/g	< 0.0003	ug/g
BENZO(a)PYRENE:	< 0.0004	ug/g	< 0.0004	ug/g
DIBENZO(a,h)ANTHRACENE:	< 0.0005	ug/g	< 0.0005	ug/g
BENZO(g,h,i)PERYLENE:	< 0.001	ug/g	< 0.001	ug/g

[ug/g = micrograms/gram = parts/million]

The cost of this special analysis was $ 518.40